

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Midcontinent	)	Order No. 202-26-29
Independent System Operator and	)	
Northern Indiana Public Service	)	
Company LLC	)	

Federal Power Act Section 202(c)	)	
Emergency Order: Midcontinent	)	Order No. 202-26-30
Independent System Operator and	)	
CenterPoint Energy Indiana South	)	

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 191
June Schahfer Order



Department of Energy
Washington, DC 20585

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

Order No. 202-26-29

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),¹ and section 301(b) of the Department of Energy (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 Midwest region of the United States (U.S.) due to a shortage of electric energy, a shortage of facilities for the generation 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 generation units and two coal-fired generation units, Unit 17 (423.5 MW) and Unit 18 (423.5 MW).³ Unit 17 and Unit 18 began operations in 1983 and 1986, respectively. Unit 17 and Unit 18 were both slated to cease operations in December 2025.⁴

Order No. 202-25-12, issued pursuant to FPA section 202(c), required that Schahfer Unit 17 and Unit 18 remain in operation for 90 days, through March 23, 2026. Subsequently, Order No. 202-26-19, issued pursuant to FPA section 202(c), required the Schahfer Units to remain in operation for 90 days, until June 21, 2026. These orders

¹ 16 U.S.C. § 824a(c).

² 42 U.S.C. § 7151(b).

³ U.S. Energy Info. Admin., *Form EIA-860, Schedule 3: Generator Data* (2024), <https://www.eia.gov/electricity/data/eia860/>.

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 (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 the Midcontinent Independent System Operator, Inc. (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 would provide additional generation capacity during these periods, which would help prevent the loss of power to homes and businesses that would otherwise pose a risk to public health and safety.⁶ I determined that the continued operation of Schahfer 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 (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 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

Second, MISO’s year-round resource adequacy concerns are well-documented. In 2022, MISO requested Federal Energy Regulatory Commission (FERC) approval of 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.¹⁰ MISO justified this revision by explaining that “Reliability risks associated with [r]esource [a]dequacy have shifted from ‘Summer only’ to a year-round concern.”¹¹

⁵ See, e.g., *Midcontinent Indep. Sys. Operator, Inc.*, DOE Order No. 202-25-12, at 1–4 (Dec. 23, 2025).

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.

¹⁰ *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*, 182 FERC ¶ 61,096 (2023).

¹¹ *MISO*, Transmittal Letter, FERC Dkt. No. ER22-495-000, at 3.

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.¹²

CONTINUING EMERGENCY CONDITIONS

The emergency conditions that necessitated the issuance of Order Nos. 202-25-12 and 202-26-19 continue, both in the near and long term. The production of electricity from Schahfer continues to be critical to maintain reliability in MISO. MISO’s resource adequacy concerns were most recently demonstrated during Winter Storm Fern, when Schahfer operated under a cold weather alert and declared conservative operations from January 23–February 1, 2026. On January 24, MISO declared an Energy Emergency Alert (EEA) 1, as well as an EEA 2 “MaxGen” event for MISO’s North and Central Regions due to generation outages, high demand, and transfer capability limits.¹³ From January 21–February 1, 2026, Schahfer operated at over 285 MW every day.¹⁴

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.¹⁵ 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. MISO also projected risk of loss of load in the winter and spring seasons, which, although not as high as in the summer or fall, will nevertheless increase over time.¹⁶

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*.¹⁷ 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,

¹² *Id.* at 3–4.

¹³ See MISO (@MISO_energy), X (Jan. 24, 2026), https://x.com/MISO_energy/status/2015072060876140805?s=20.

¹⁴ DOE, *FACT SHEET: Energy Dep’t Prevented Blackouts & Saved Am. Lives During Winter Storms* (Feb. 2026), <https://www.energy.gov/articles/fact-sheet-energy-department-prevented-blackouts-saved-american-lives-during-winter-storms>.

¹⁵ MISO, *Attributes Roadmap*, at 3 (Dec. 2023), <https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf>.

¹⁶ *Id.* at 11.

¹⁷ MISO, *MISO’s Response to the Reliability Imperative* (updated Feb. 2024), <https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf>.

creating risks in non-summer months that rarely posed challenges in the past.¹⁸ 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, NERC assessed that the MISO region is at high risk of energy shortfalls over the next five years, stating that it faces significant reliability challenges as “projected resource additions do not keep pace with escalating demand forecasts and announced generator retirements.”¹⁹ This determination is based on the combination of accelerating demand growth from new data centers and the retirement of existing thermal generators.²⁰ The 2025 Long-Term Reliability Assessment notes that “MISO’s accredited thermal capacity has decreased by 8.8 GW, driven primarily by reductions in accredited capacity of existing facilities and retirements.”²¹ The report observes that winter peak periods are a particular concern, with projections showing “shortfalls in planned resources for winter peak periods.”²² 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.”²³

According to NERC’s 2026 Summer Reliability Assessment, load growth in the MISO region, led by data centers, “is expected to accelerate in 2027 and beyond, which may lead to increased reliability risk in the future if resource additions cannot keep pace with rising load forecasts.”²⁴ It further notes 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].”²⁵ 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.²⁶

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

¹⁸ *Id.* at 12.

¹⁹ NERC, *2025 Long-Term Reliability Assessment*, at 7–8 (Jan. 2026), https://prod.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

²⁰ *Id.* at 43.

²¹ *Id.* at 15.

²² *Id.*

²³ *Id.*

²⁴ NERC, *2026 Summer Reliability Assessment*, at 16 (May 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_sra_2026.pdf.

²⁵ *Id.* at 16.

²⁶ *Id.* at 16.

the negative impacts of decreased accreditation, suspensions/retirements and external resources” in the northern and central zones, which include Indiana.²⁷

On June 6, 2025, the Organization of MISO States (OMS) and MISO issued the results of their annual survey (OMS-MISO Survey), which reported the degree to which expected capacity resources satisfy planning reserve margin requirements.²⁸ The OMS-MISO Survey presented projections of resource adequacy for the summer of 2026 and subsequent years. Although the OMS-MISO Survey projected a potential capacity surplus for the summer of 2026, it also projected that at least 3.1 GW of additional generation capacity beyond currently committed generation capacity must be added to meet the projected planning reserve margin. The OMS-MISO Survey also projected that there would be insufficient capacity to meet the peak demand for electricity in each of the following four summers, increasing from a deficit of 1.4 GW in 2027 to 8.2 GW in 2030.²⁹ It also projected similar results for MISO’s winter seasons, with a small surplus of generation capacity in 2026, followed by increasing deficits the following four years.³⁰

The primary reasons for these projected deficits also are shown on the OMS-MISO Survey. Large amounts of existing generation capacity are projected to be retired each year, while, at the same time, the demand for electricity is projected to increase at an accelerating pace.³¹ Although the OMS-MISO survey projects generation capacity to continue to increase in the coming years with the addition of new potential generation assets, the increase in capacity is largely offset by the projected retirements and does not keep up with the growth in demand.³²

According to the U.S. Energy Information Administration, coal-fired electricity generation in Indiana has declined from 85% of total generation in 2014 to 42% in 2024. Since 2014, approximately 5,000 MW of coal-fired capacity in Indiana have retired, with nearly another 3,900 MW of coal-fired capacity scheduled for retirement by the end of 2028, which includes Schahfer’s capacity.³³

²⁷ 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.

²⁸ OMS and MISO, *OMS-MISO Survey Results* (updated June 6, 2025), <https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf>.

²⁹ *Id.* at 7.

³⁰ *Id.* at 9.

³¹ *Id.* at 7, 9.

³² *Id.*

³³ See U.S. Energy Info. Admin. , *Indiana Analysis* (Nov. 19, 2025), <https://www.eia.gov/states/in/analysis>.

MISO has been taking steps to address these projected deficits, but the solution is years away. 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, 2025.³⁴ The ERAS process 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 after the process begins and are provided an additional three-year grace period to commence commercial operations.³⁵ 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.³⁶ 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 and 202-26-19 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.”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 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.”³⁹

³⁴ *Midcontinent Indep. Sys. Operator, Inc.*, 192 FERC ¶ 61,064 (2025).

³⁵ *See id.* P 84.

³⁶ *See generally* S&P Global, *US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply* (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>.

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>.

In addition, President Trump issued a White House Memo for 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 . . . 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 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.”⁴¹

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.”⁴²

Grid operators—including MISO itself—have also acknowledged the Nation’s current energy crisis. For instance, during a March 25, 2025, hearing before the House Committee on Energy and Commerce, Jennifer Curran, Senior Vice President, Planning and Operations, MISO, testified that “the MISO region faces resource adequacy and reliability challenges due to the changing characteristics of the electric generating fleet, inadequate transmission system infrastructure, growing pressures from extreme weather, and rapid load growth.”⁴³

Ms. Curran also described “much stronger growth [in demand for electricity] from continued electrification efforts, a resurgence in manufacturing, and an unexpected

⁴⁰ 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/>.

⁴¹ *Id.*

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/2025-11/DOE%20Final%20EO%20Report%20%28REVISED%20OCT%2027%29.pdf>.

⁴³ *Keeping the Lights On: Examining the State of Reg’ Grid Reliability; Hearing Before the House Comm. on Energy & Com., Subcomm. on Energy*, 119th Cong. 5 (2025) (statement of Ms. Jennifer Curran, Senior Vice President for Planning and Operations, Midcontinent Indep. Sys. Operator), <https://www.congress.gov/119/meeting/house/118040/witnesses/HHRG-119-IF03-Wstate-CurranJ-20250325.pdf>.

demand for energy-hungry data centers to support artificial intelligence.”⁴⁴ 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.”⁴⁵

ORDER

FPA section 202(c)(1) provides that whenever 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 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.”⁴⁶ 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 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 emergency conditions resulting from increasing demand and shortage from accelerated 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 September 19, 2026.

⁴⁴ *Id.* at 6.

⁴⁵ *Id.* at 7.

⁴⁶ 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 June 22, 2026, MISO and NIPSCO 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 the allowances contained in 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 July 7, 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. MISO 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. NIPSCO 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 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 June 22, 2026, through September 19, 2026, with the exception of applicable compliance obligations in paragraph D.

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

Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Indiana Utility Regulatory Commissioners
Chairman Andy Zay
Commissioner Bob Deig
Commissioner Anthony Swinger
Commissioner David Veleta
Commissioner David Ziegner

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 192
June Culley Order



Department of Energy
Washington, DC 20585

Midcontinent Independent System Operator, Inc.
Center Point Energy
Regarding F.B. Culley Generating Station

Order No. 202-26-30

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),¹ and section 301(b) of the Department of Energy (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 Midwest region of the United States (U.S.) due to a shortage of electric energy, a shortage of facilities for the generation 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 generation units, Unit 2 (103.7 MW) and Unit 3 (265.2 MW), with a combined name plate 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 No. 202-25-13, issued pursuant to FPA section 202(c), required that Culley Unit 2 remain in operation for 90 days, through March 23, 2026. Subsequently, Order No. 202-26-20, issued pursuant to FPA section 202(c), required the Culley Unit to remain in operation for 90 days, until June 21, 2026. These orders were based on my determination that emergency conditions existed in the region served by the Midcontinent Independent System Operator, Inc. (MISO).

¹ 16 U.S.C. § 824a(c).

² 42 U.S.C. § 7151(b).

³ U.S. Energy Info. Admin., *Form EIA-860, Schedule 3: Generator Data* (2024), <https://www.eia.gov/electricity/data/eia860/>.

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 (Aug. 2021), https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-31348.pdf.

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 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 (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 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

Second, MISO’s year-round resource adequacy concerns are well-documented. In 2022, MISO requested Federal Energy Regulatory Commission (FERC) approval of 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.¹⁰ MISO justified this revision by explaining that “Reliability risks associated with [r]esource [a]dequacy have shifted from ‘Summer only’ to a year-round concern.”¹¹ MISO noted that over 60% of all “MaxGen” events (events when MISO initiates

⁵ See, e.g., *Midcontinent Indep. Sys. Operator, Inc.*, Order No. 202-25-12, at 1–4 (Dec. 23, 2025).

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/nerc_ltra_2025.pdf.

⁹ *Id.* at 44.

¹⁰ *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).

¹¹ *MISO*, Transmittal Letter, FERC Dkt. No. ER22-495-000, at 3.

emergency procedures because of concerns over the adequacy of available generation) occurred outside of the summer season.¹²

CONTINUING EMERGENCY CONDITIONS

The emergency conditions that necessitated the issuance of Order Nos. 202-25-13 and 202-26-20 continue, both in the near and long term. The production of electricity from Culley continues to be critical to maintain reliability in MISO. MISO's resource adequacy concerns were most recently demonstrated during Winter Storm Fern, when Culley operated under a cold weather alert and declared conservative operations from January 23–February 1, 2026. On January 24, MISO declared an Energy Emergency Alert (EEA) 1, as well as an EEA 2 “MaxGen” event for MISO's North and Central Regions due to generation outages, high demand, and transfer capability limits.¹³ From January 21–February 1, 2026, Culley operated at roughly 30 MW almost every day.¹⁴

In December of 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.”¹⁵ 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. MISO also projected risk of loss of load in the winter and spring seasons; which although not as high as in the summer or fall, will nevertheless increase over time.¹⁶

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*.”¹⁷ 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,

¹² *Id.* at 3–4.

¹³ See MISO (@MISO_energy), X, (Jan. 24, 2026), https://x.com/MISO_energy/status/2015072060876140805?s=20.

¹⁴ DOE, *FACT SHEET: Energy Dep't Prevented Blackouts & Saved Am. Lives During Winter Storms*, (Feb. 2026), <https://www.energy.gov/articles/fact-sheet-energy-department-prevented-blackouts-saved-american-lives-during-winter-storms>.

¹⁵ MISO, *Attributes Roadmap*, *supra* note 14, at 3.

¹⁶ *Id.* at 11.

¹⁷ MISO, *MISO's Response to the Reliability Imperative* (Updated Feb. 2024), <https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf>.

creating risks in non-summer months that rarely posed challenges in the past.¹⁸ 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, NERC assessed that the MISO region is at high risk of energy shortfalls over the next five years, stating that it faces significant reliability challenges as “projected resource additions do not keep pace with escalating demand forecasts and announced generator retirements.”¹⁹ This determination is based on the combination of accelerating demand growth from new data centers and the retirement of existing thermal generators.²⁰ The 2025 Long-Term Reliability Assessment notes that “MISO’s accredited thermal capacity has decreased by 8.8 GW, driven primarily by reductions in accredited capacity of existing facilities and retirements.”²¹ The report observes that winter peak periods are a particular concern, with projections showing “shortfalls in planned resources for winter peak periods.”²² 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.”²³

According to NERC’s 2026 Summer Reliability Assessment, load growth in the MISO region, led by data centers, “is expected to accelerate in 2027 and beyond, which may lead to increased reliability risk in the future if resource additions cannot keep pace with rising load forecasts.”²⁴ It further notes 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].”²⁵ 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.²⁶

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

¹⁸ *Id.* at 12.

¹⁹ NERC, *2025 Long-Term Reliability Assessment*, at 7–8 (Jan. 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

²⁰ *Id.* at 43.

²¹ *Id.* at 15.

²² *Id.*

²³ *Id.*

²⁴ NERC, *2026 Summer Reliability Assessment*, at 16 (May 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_sra_2026.pdf.

²⁵ *Id.* at 16.

²⁶ *Id.* at 16.

the negative impacts of decreased accreditation, suspensions/retirements and external resources” in the northern and central zones, which include Indiana.²⁷

On June 6, 2025, the Organization of MISO States (OMS) and MISO issued the results of their annual survey (OMS-MISO Survey), which reported the degree to which expected capacity resources satisfy planning reserve margin requirements.²⁸ The OMS-MISO Survey presented projections of resource adequacy for the summer of 2026 and subsequent years. Although the OMS-MISO Survey projected a potential capacity surplus for the summer of 2026, it also projected that at least 3.1 GW of additional generation capacity beyond currently committed generation capacity must be added to meet the projected planning reserve margin. The OMS-MISO Survey also projected that there would be insufficient capacity to meet the peak demand for electricity in each of the following four summers, increasing from a deficit of 1.4 GW in 2027 to 8.2 GW in 2030.²⁹ It also projected similar results for MISO’s winter seasons, with a small surplus of generation capacity in 2026, followed by increasing deficits the following four years.³⁰

The primary reasons for these projected deficits also are shown on the OMS-MISO Survey. Large amounts of existing generation capacity are projected to be retired each year, while, at the same time, the demand for electricity is projected to increase at an accelerating pace.³¹ Although the OMS-MISO survey projects generation capacity to continue to increase in the coming years with the addition of new potential generation assets, the increase in capacity is largely offset by the projected retirements and does not keep up with the growth in demand.³²

According to the U.S. Energy Information Administration, coal-fired electricity generation in Indiana has declined from 85% of total generation in 2014 to 42% in 2024. Since 2014, approximately 5,000 MW of coal-fired capacity in Indiana have retired, with nearly another 3,900 MW of coal-fired capacity scheduled for retirement by the end of 2028, which includes Culley’s capacity.³³

MISO has been taking steps to address these projected deficits, but the solution is years away. For example, on June 6, 2025, MISO submitted a proposal to FERC to

²⁷ 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.

²⁸ OMS and MISO, *OMS-MISO Survey Results* (updated June 6, 2025), <https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf>.

²⁹ *Id.* at 7.

³⁰ *Id.* at 9.

³¹ *Id.* at 7, 9.

³² *Id.*

³³ *See U.S. Energy Info. Admin., Indiana Analysis* (Nov. 19, 2025), <https://www.eia.gov/states/in/analysis>.

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, 2025.³⁴ The ERAS process 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 after the process begins and are provided an additional three-year grace period to commence commercial operations.³⁵ 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.³⁶ 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 and 202-26-20 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.”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 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.”³⁹

³⁴ *Midcontinent Indep. Sys. Operator, Inc.*, 192 FERC ¶ 61,064 (2025).

³⁵ *See id.* P 84.

³⁶ *See generally* S&P Global, *US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply* (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>.

³⁷ Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), <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>.

In addition, President Trump issued a White House Memo for 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 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 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.”⁴¹

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.”⁴²

Grid operators—including MISO itself—have also acknowledged the Nation’s current energy crisis. For instance, during a March 25, 2025 hearing before the House Committee on Energy and Commerce, Jennifer Curran, Senior Vice President, Planning and Operations, MISO, testified that “the MISO region faces resource adequacy and reliability challenges due to the changing characteristics of the electric generating fleet, inadequate transmission system infrastructure, growing pressures from extreme weather, and rapid load growth.”⁴³

Ms. Curran also described “much stronger growth [in demand for electricity] from continued electrification efforts, a resurgence in manufacturing, and an unexpected

⁴⁰ 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/>).

⁴¹ *Id.*

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%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf>.

⁴³ *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, Midcontinent Indep. Sys. Operator), <https://www.congress.gov/119/meeting/house/118040/witnesses/HHRG-119-IF03-Wstate-CurranJ-20250325.pdf>.

demand for energy-hungry data centers to support artificial intelligence.”⁴⁴ 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.”⁴⁵

ORDER

FPA section 202(c)(1) provides that whenever 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 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.”⁴⁶ 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 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 emergency conditions resulting from increasing demand and shortage from accelerated 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), Culley Unit 2 shall be made available for operation through September 19, 2026.

⁴⁴ *Id.* at 6.

⁴⁵ *Id.* at 7.

⁴⁶ 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 June 22, 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 the allowances contained in 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 July 7, 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. MISO 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. CenterPoint Energy 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 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 June 22, 2026, through September 19, 2026, with the exception of applicable compliance obligations in paragraph D.

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

Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
 Chairman Laura V. Swett
 Commissioner David Rosner
 Commissioner Lindsay S. See
 Commissioner Judy W. Chang
 Commissioner David A. LaCerte

Indiana Utility Regulatory Commissioners
 Chairman Andy Zay
 Commissioner Bob Deig
 Commissioner Anthony Swinger
 Commissioner David Veleta
 Commissioner David Ziegner

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Midcontinent	)	Order No. 202-26-29
Independent System Operator and	)	
Northern Indiana Public Service	)	
Company LLC	)	

Federal Power Act Section 202(c)	)	
Emergency Order: Midcontinent	)	Order No. 202-26-30
Independent System Operator and	)	
CenterPoint Energy Indiana South	)	

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 193
PIOs' April Rehearing Request

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Midcontinent	)	Order No. 202-26-19
Independent System Operator	)	
(MISO) and Northern Indiana	)	
Public Service Company LLC	)	
	)	
Federal Power Act Section 202(c)	)	
Emergency Order: Midcontinent	)	Order No. 202-26-20
Independent System Operator	)	
(MISO) and CenterPoint Energy	)	
Indiana South	)	

Motion to Intervene and Request for Rehearing and Stay of
Sierra Club, Citizens Action Coalition of Indiana, Just Transition Northwest
Indiana, Hoosier Environmental Council, Environmental Law and Policy Center,
and Public Citizen (collectively, “Public Interest Organizations” or “PIOs”)

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I. INTRODUCTION

The Department of Energy (“Department”) is unlawfully using Section 202(c) of the Federal Power Act, 16 U.S.C. § 824a(c), to prevent the retirement of two coal-fired power plants in Indiana: Units 17 and 18 of the R.M. Schahfer Generating Station (“Schahfer”) and Unit 2 of the F.B. Culley Generating Station (“Culley 2”) (collectively, the “Plants”), which are very expensive and very toxic to operate. The Department is acting pursuant to a new and unprecedented policy to exceed its carefully constrained emergency authority under Section 202(c) in order to prevent coal plant retirements. The policy is unlawful because Section 202(c) applies only to imminent, unexpected shortfalls, not to the Department’s preference for specific types of energy generation.

NIPSCO and Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South (“CenterPoint Indiana”), which owns Culley 2, determined pursuant to years-long, state-mandated integrated resource planning (“IRP”) processes that the Plants are no longer needed to serve customer demand past 2025. Accordingly, NIPSCO and CenterPoint Indiana long ago resolved to close the Plants in December 2025.

That long-anticipated transition was disrupted at the end of last year when the Department issued two 90-day orders under Section 202(c) of the Federal Power Act, 16 U.S.C. § 824a(c). See Order No. 202-25-12 (Exhibit 1, the “December Schahfer Order”) and Order No. 202-25-13 (Exhibit 2, the “December Culley Order”) (collectively, the “December Orders”). Neither of the December Orders offered any lawful basis, rational reasoning, or legitimate evidentiary support for a near-term or long-term emergency justifying the invocation of Section 202(c). And now, despite Public Interest Organizations refuting the Department’s mischaracterizations or misunderstandings of the sources on which it relies (Ex. 168, PIOs’ January Rehearing Request), the Department has renewed both orders. See Order No. 202-26-19 (the “March Schahfer Order”) and Order No. 202-26-20 (the “March Culley Order”) (collectively, the “Orders”). In its quest to keep the affected coal power plants operating, regardless of whether there is an actual shortage the Plants are needed to address, the Department has declined to consider a mountain of evidence contrary to its position. The policy is also unlawful in substance because the carefully constrained emergency authority of Section 202(c) applies only to imminent, unexpected shortfalls, not to the Department’s preference for specific types of energy generation.

The Department justifies these intrusive and unnecessary orders by alleging concerns about resource adequacy and reliability, but its concerns are based on selective quotations of some documents, elementary misunderstandings or

mischaracterizations of additional documents, and disregard of governing law to engage in a forbidden effort to usurp others' authority. Additionally, the Department fails to reconcile its concerns with the Department's existing authorizations to export power from MISO in which, for instance, the Department finds that markets in the area are sufficiently robust to make supplies available and that multi-layered and comprehensive reliability processes incentivize maintenance of system resources. Moreover, the concerns expressed in the Orders are primarily not focused on the actual 90-day period at issue (*i.e.*, the period starting on March 23, 2026 and extending to June 21, 2026). The evidence shows there is every reason to believe that the actors with authority over resource adequacy and reliability—FERC, NERC, MISO, Indiana regulators, the electric utility owners, and others—have provided for adequate resources and reliability in the Spring 2026 and Summer 2026 seasons, in all arguably relevant geographies, and will continue doing so going forward..

The Orders will cause (just as the December Orders have caused) significant harm. The significant cost of running the Plants, hundreds of thousands of dollars a day, are likely to be borne by households and families in Indiana and ten nearby states. *See infra* sec. IV.C.3; Ex. 5 (Synapse Report); *Northern Indiana Public Service Company LLC v. MISO*, 194 FERC ¶ 61,215 at PP 36-37 (2026); *Southern Indiana Gas and Electric Company v. MISO*, 194 FERC ¶ 61,214 at PP 34-35 (2026). The Department and the federal administration admit that “[a]ll costs” incurred by an affected power plant under a Section 202(c) emergency order “end up on ratepayers.” *See* Laura Sanicola, Barrons, *Who’s Paying to Keep Coal Plant Alive? All Electricity Customers, Trump Advisor Says* (Jan. 14, 2026), <https://www.msn.com/en-us/money/markets/who-s-paying-to-keep-coal-plant-alive-all-electricity-customers-trump-advisor-says/ar-AA1UdRHI>; Orders at 9 (each stating that “[r]ate recovery is available”)

And there are other more deadly costs as well. Schahfer and Culley 2 are dirty, old plants that spew pollution into the air and into the Kankakee and Ohio Rivers. *See infra* sec. IV.C.3. Operation of all these units leads to premature deaths and deepens the harms to communities already injured by decades of environmental pollution. *See id.*

Public Interest Organizations thus respectfully request that the Department grant intervention; stay the Orders; grant rehearing and rescind the Orders (and

any renewals of the Orders); and allow the two Indiana Plants at issue—Schahfer and Culley 2—to retire as planned.¹

II. STATEMENT OF ISSUES AND SPECIFICATION OF ERROR

The undersigned Public Interest Organizations move to intervene and request rehearing and a stay of both Orders pursuant to Section 313(a) of the Federal Power Act, 16 U.S.C. § 825l(a), and the applicable rules of practice and procedure, 18 C.F.R. §§ 385.203, .212, .214, .713; *see* Ex. 8 at PDF 2 (Cooke Email to Alle-Murphy) (recommending that “a party seeking rehearing can look for procedural guidance to [Federal Energy Regulatory Commission’s (“FERC”)] Rules of Practice and Procedure, 18 CFR Part 385.”).² Public Interest Organizations’ motion and requests are based upon the following errors and issues:

- A. The Department has not demonstrated that an emergency exists in any portion of MISO as required by Section 202(c) of the Federal Power Act; nor has the Department demonstrated that an emergency exists as defined in the implementing regulations for Section 202(c). *See, e.g.*, 16 U.S.C §§ 824(a)–(b),

¹ Because the two Orders employ nearly identical language and reasoning and are both addressed to power generating plants in the Indiana zone of the MISO transmission grid, Public Interest Organizations are here submitting a single Request for Rehearing applicable to each of the Orders.

² Until sometime after June 18, 2025, the Department maintained a webpage with procedures for intervention and rehearing requests. U.S. Dep’t of Energy, *DOE 202(c) Order Rehearing Procedures* (visited June 18, 2025), <https://www.energy.gov/ceser/doe-202c-order-rehearing-procedures> (attached as Ex. 30) [hereinafter “DOE Rehearing Procedures”]. The Department maintains another website which currently states, “All public comments and requests related to FPA section 202(c) should be sent via email to AskCR@hq.doe.gov. . . . Additional information about 202(c) procedures, if necessary, will be announced on this page. The provision of this process for submission of correspondence or comments on any pending application is for purposes of ensuring the receipt by the appropriate office and personnel within the Department. Establishment of this email address does not establish a ‘docket,’ and those submitting correspondence do not constitute parties or intervenors to any proceeding.” U.S. Dep’t of Energy, *DOE’s Use of Federal Power Act Emergency Authority* (last visited Jan. 22, 2025), <https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority> (attached as Ex. 74) [hereinafter “DOE 202(c) Webpage”]. Public Interest Organizations’ instant motion and requests are also pursuant to the DOE 202(c) Webpage and the DOE Rehearing Procedures.

824a(a)–(c); 10 C.F.R. §§ 205.371–.375; *Emergency Interconnection of Elec. Facilities and the Transfer of Elec. to Alleviate an Emergency Shortage of Elec. Power*, 46 Fed. Reg. 39984 (Aug. 6, 1981); *Hughes v. Talen Energy Mktg., LLC*, 578 U.S. 150 (2016); *FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120 (2000); *Jarecki v. G.D. Searle & Co.*, 367 U.S. 303 (1961); *Citizens Action Coal. v. FERC*, 125 F.4th 229 (D.C. Cir. 2025); *Conn. Dep’t of Pub. Util. Control v. FERC*, 569 F.3d 477 (D.C. Cir. 2009); *Alcoa Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009); *Cal. Indep. Sys. Op. Corp. v. FERC*, 372 F.3d 395 (D.C. Cir. 2004); *Otter Tail Power Co. v. Federal Power Commission*, 429 F.2d 232 (8th Cir. 1970); *Richmond Power & Light v. FERC*, 574 F.2d 610, 615 (D.C. Cir. 1978); *Duke Power Co. v. Fed. Power Com.*, 401 F.2d 930, 938 (D.C. Cir. 1968).

- B. Even if the emergency described by the Orders did exist—it does not—the Department has not demonstrated a reasoned basis for its determination that additional dispatch of Schahfer and Culley 2 is necessary to “best meet the emergency and serve the public interest.” See, e.g., 16 U.S.C. § 824a(c); 10 C.F.R. §§ 205.373, 205.375; *Dep’t of Homeland Sec. v. Regents of the Univ. of Calif.*, 591 U.S. 1 (2020); *Entergy Corp. v. Riverkeeper, Inc.*, 556 U.S. 208 (2009); *Allentown Mack Sales & Service, Inc. v. NLRB*, 522 U.S. 359 (1998); *Motor Vehicle Mfrs. Ass’n of the U.S. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29 (1983); *NAACP v. Fed. Power Comm’n*, 425 U.S. 662 (1976); *Gulf States Utils. Co. v. Fed. Power Comm’n*, 411 U.S. 747 (1973); *Otter Tail Power Co. v. United States*, 410 U.S. 366 (1973); *California v. Fed. Power Comm’n*, 369 U.S. 482 (1962); *Pa. Water & Power Co. v. Fed. Power Comm’n*, 343 U.S. 414 (1952); *Nat’l Shooting Sports Found., Inc. v. Jones*, 716 F.3d 200 (D.C. Cir. 2013); *Chamber of Com. of the U.S. v. Secs. & Exch. Comm’n*, 412 F.3d 133 (D.C. Cir. 2005); *Sierra Club v. Env’t. Prot. Agency*, 353 F.3d 976, 980 (D.C. Cir. 2004); *Wabash Valley Power Ass’n, Inc. v. FERC*, 268 F.3d 1105 (D.C. Cir. 2001).
- C. The Orders’ availability requirements and override of Schahfer and Culley 2’s federal tariff-defined capacity treatment each exceed the Department’s authority and are unreasoned. See, e.g., 16 U.S.C. §§ 824(a)–(b), 824a(b)–(c); *Gallardo v. Marstiller*, 596 U.S. 420 (2022); *Hughes v. Talen Energy Mktg., LLC*, 578 U.S. 150 (2016); *FERC v. Elec. Power Supply Ass’n*, 577 U.S. 260 (2016); *Gomez-Perez v. Potter*, 553 U.S. 474 (2008); *Allentown Mack Sales & Service, Inc. v. NLRB*, 522 U.S. 359 (1998); *Fed. Power Comm’n v. Fla. Power & Light Co.*, 404 U.S. 453 (1972); *Conn. Light & Power v. Fed. Power Comm’n*, 324 U.S. 515 (1945); *Conn. Dep’t of Pub. Util. Control v. FERC*, 569 F.3d 477 (D.C. Cir. 2009).

D. The Department has unlawfully failed to ensure that the Orders require generation of electric energy only during hours necessary to meet the emergency and serve the public interest, that operations are consistent with any applicable environmental laws and regulations to the maximum extent practicable, and that any adverse environmental impacts are minimized. *See, e.g.*, 16 U.S.C. § 824a(c)(2); *Kingdomware Techs., Inc. v. United States*, 579 U.S. 162 (2016); *Fla. Power & Light Co. v. FERC*, 88 F.3d 1239 (D.C. Cir. 1996); *City of New Orleans v. FERC*, 67 F.3d 947 (D.C. Cir. 1995); Ex. 9 (DOE Order No. 202-22-4); Ex. 6 (DOE Order No. 202-17-4 Summary of Findings); Ex. 110 (DOE Order No. 202-24-1); Ex. 160 (Department Order No. 202-26-01); Ex. 161 (Department Order No. 202-26-01A)..

III. INTERVENORS' INTERESTS

As further discussed below, each of the Public Interest Organizations has interests that may be directly and substantially affected by the outcome of these proceedings. Each party may therefore intervene in these proceedings. 18 C.F.R. § 385.214; *see* Ex. 30 (DOE Rehearing Procedures); Ex. 74 (DOE 202(c) Webpage); Ex. 8 (Cooke Email to Alle-Murphy).

The Public Interest Organizations also demonstrate concrete injuries arising from the Orders that are redressable by a favorable outcome. Each organization is therefore aggrieved by the Department's Orders and may properly apply for rehearing. *See* 16 U.S.C. § 825l(a); *Wabash Valley Power Ass'n, Inc. v. FERC*, 268 F.3d 1105, 1112 (D.C. Cir. 2001); 18 C.F.R. §§ 385.203, 385.713; Ex. 30 (DOE Rehearing Procedures); Ex. 74 (DOE 202(c) Webpage); Ex. 8 (Cooke Email to Alle-Murphy).

A. *Sierra Club*

As of March 2026, over 8,000 Sierra Club members reside in Indiana. Sierra Club members are harmed by pollution produced by operating the Culley and Schahfer coal units. Sierra Club has over 900 members in Jasper County, Indiana, where Schahfer is located, and the adjoining counties. Sierra Club has approximately 300 members in Warrick County, Indiana, where Culley is located, and the adjoining counties. The Orders to operate these Plants beyond their planned retirement date will subject Sierra Club members to additional air and water pollution in the areas where they live, work, and recreate. In addition, Sierra Club members include people who pay for electricity from CenterPoint Indiana and NIPSCO.

Sierra Club has demonstrated an organizational commitment to the interests of reducing pollution and harm from these coal-burning power plants. Sierra Club's Beyond Coal Campaign seeks to reduce the pollution currently being produced by coal-burning power plants such as Culley and Schahfer, and to reduce energy bills by ensuring that ratepayers do not fund the cost of continuing to operate uneconomic coal plants like Culley and Schahfer. To those ends, Sierra Club has advocated for the retirement of the Culley plant in multiple regulatory proceedings, including CenterPoint Indiana's 2016, 2020, 2023, and 2025 Integrated Resource Plan stakeholder processes, a fuel adjustment clause docket related to forced outages at the Culley plant, and electric rate cases. Sierra Club has also submitted comments to the Indiana Department of Environmental Management on draft air and water permits for the Culley plant, advocating for more stringent pollution requirements. Sierra Club has advocated for the retirement of Schahfer in several regulatory proceedings, including a certificate of public necessity proceeding for retrofits at the Schahfer plant in 2017, and NIPSCO's 2014, 2016, and 2018 Integrated Resource Plan stakeholder processes. In 2019, Sierra Club signed a multi-party settlement in NIPSCO's electric rate case that adjusted the depreciation schedule for the Schahfer plant to align with a 2023 retirement and that provided that electric customers were to receive a bill credit upon the plant's retirement.

Sierra Club has invested staff and volunteer time, as well as significant financial resources to hire experts, to advocate for the retirement of Culley and Schahfer. Sierra Club has submitted hundreds of individual comments to the utilities and Indiana Commission advocating for the retirement of these coal units. By denying these and other benefits of the Culley 2 and Schahfer Plants' retirements, the Orders harm Sierra Club and its members.

B. Citizens Action Coalition of Indiana

Citizens Action Coalition of Indiana, Inc. ("CAC") is Indiana's oldest and largest consumer and environmental advocacy organization. Since 1974, CAC has helped Hoosiers save more than \$10 billion in excess utility charges. CAC advocates on behalf of Hoosiers on issues regarding energy policy, utility reform, health care, pollution prevention, and family farms. CAC's activities include research, public education, organizing citizens, lobbying, intervening in utility cases before the Indiana Utility Regulatory Commission ("IURC"), and litigating when necessary. CAC engages in rate cases, cost recovery proceedings, certificates of public convenience and necessity proceedings, demand side management proceedings, and numerous other matters impacting the cost or reliability of Hoosiers' energy services, including numerous proceedings associated with the planned retirements of Schahfer and Culley 2. CAC also participates in the rigorous Integrated Resource

Plan stakeholder processes required for Indiana’s jurisdictional electric utilities submitting integrated resource plans every three years according to Indiana Code § 8-1-8.5-3(e)(2).

C. Just Transition Northwest Indiana

Just Transition Northwest Indiana (“JTNWI”), a nonprofit corporation chartered under the laws of Indiana, is a grassroots environmental justice organization serving the Northwest Indiana region, primarily Lake, Porter, LaPorte, and Jasper Counties, that centers on organizing and base-building activities. JTNWI’s mission is to educate and organize Northwest Indiana communities and workers, give voice to our shared stories, and support a just transition to a regenerative economy that protects the environment, climate, and future generations. Since the organization’s formation in 2020, JTNWI has worked tirelessly on issues related to utility affordability, pollution response and accountability, and industrial decarbonization within the NIPSCO service territory, including Wheatfield and Jasper County, Indiana, where the R.M. Schahfer Generating Station is located, communities JTNWI serves whose health and livelihoods will be adversely impacted by the 202(c) emergency order. JTNWI works across the local, state, and federal levels, including advocating for coal ash waste clean closures, plant retirements, and just transition planning in fossil fuel-impacted communities in the region, and is actively involved in public comment periods and interventions in NIPSCO electric rate cases before the Indiana Utility Regulatory Commission and in environmental permits with the Indiana Department of Environmental Management and the United States Environmental Protection Agency.

D. Hoosier Environmental Council

Hoosier Environmental Council, Inc. (“HEC”) is a 501(c)(3), non-profit, public interest environmental policy and advocacy organization chartered under the laws of Indiana. Since its formation in 1983, HEC has been and continues to be committed to protecting Indiana’s air, land, waterways and wildlife habitat through initiatives in education, research, technical assistance, public policy advocacy, and legal action including the enforcement of federal and state laws that protect Indiana’s natural resources. To further its mission, HEC actively seeks federal and state agency implementation and enforcement of environmental laws and regulations, and when necessary initiates enforcement actions on behalf of HEC and its members. For more than 40 years, HEC has advocated for measures to reduce the harm that coal-fired power does to land, air, water, and human health. HEC has been active regarding the Schahfer and Culley 2 sites, as well as many current and former coal-fired power plants, advocating on behalf of its members for safe closure of coal-fired power stations and proper closure of coal combustion

residual waste ponds and landfills. HEC's interest is in protection of air, water and land quality at and around these sites.

E. Public Citizen

Established in 1971, Public Citizen is a national research and advocacy organization representing the interests of household consumers. Public Citizen has members and supporters in every state, including those who pay electric utility bills in Indiana and the Midwest. Public Citizen is active before the Federal Energy Regulatory Commission promoting just and reasonable rates, and in supporting efforts for utilities to be accountable to the public. Financial details about the organization are on its website. Public Citizen, Annual Reports, www.citizen.org/about/annualreport.

F. Environmental Law and Policy Center

Environmental Law and Policy Center ("ELPC") is a not-for-profit environmental organization headquartered in Chicago with members and contributors throughout the Midwest, including in Indiana. Among other things, ELPC advocates before the Indiana Utility Regulatory Commission and the Federal Energy Regulatory Commission for clean, reliable energy generation in order to reduce ratepayer costs and improve environmental outcomes. ELPC has participated in IURC cases and matters involving NIPSCO and other Indiana utilities. See, e.g., IURC Cause No. 44688 (NIPSCO 2015 Rate Case); IURC Cause No. 45378 (Vectren Distributed Generation Rider); Duke Energy Indiana 2024 IRP.

IV. BACKGROUND

A. The Primary Actors in the Electric Industry Already Protect Resource Adequacy Without Intrusion from the Department.

1. The Federal Energy Regulatory Commission Regulates Wholesale Electricity Markets and Mechanisms that Acquire Adequate Resources.

FERC regulates wholesale sales and transmissions of electric energy in interstate commerce. 16 U.S.C. § 824(b)(1). Federal authority over the electric grid dates back at least to 1935, when the Federal Power Act became law and the Federal Power Commission administered the Act.

The Federal Power Act did not give the federal agency plenary authority over the electric grid. Instead, Congress provided that federal regulation shall "extend only to those matters which are not subject to regulation by the States" and

provided that “[t]he Commission” does not have jurisdiction, “except as specifically provided in [the Federal Power Act], over facilities used for the generation of electric energy.” *Id.* at § 824(a)–(b)(1). As such, authority over generation facilities belongs to the states. *See id.*

In 1977, through the Department of Energy Organization Act, Congress reorganized the agencies that administer the Federal Power Act. Congress created the Department of Energy and FERC. 42 U.S.C. §§ 7131, 7171(a). Congress also transferred certain functions of “the Commission” in the Federal Power Act to the Department and other functions to FERC, thereby abolishing the Federal Power Commission. *See id.* §§ 7151(b), 7172(a)(1). FERC retained authority over rates and charges for the transmission of electric energy or sale of electric energy at wholesale (in both cases, in interstate commerce), and the non-emergency interconnection of facilities for the generation, transmission, and sale of electric energy. *Id.* § 7172(a)(1)(B); 16 U.S.C. § 824(a). The Department’s authority over functions of “the Commission” in the Federal Power Act includes functions under some subsections of Section 202 of the Act. *See* 42 U.S.C. § 7151(b). The 1977 reorganization did not expand the role of the “the Commission” at the expense of state authority or shrink states’ authority over generation facilities. *See, e.g., id.* § 7113 (“Nothing in this chapter shall affect the authority of any State over matters exclusively within its jurisdiction.”).

As part of its regulatory oversight, FERC has promoted the role of nonprofit entities, known as Independent System Operators or Regional Transmission Organizations, in bulk power system operations and planning. *See FERC v. Elec. Power Supply Ass’n*, 577 U.S. 260, 267 (2016); *Regional Transm. Orgs.*, Order No. 2000, 65 Fed. Reg. 810, 811 (Jan. 6, 2000); *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transm. Servs. by Pub. Utils. and Recovery of Stranded Costs by Pub. Utils. and Transm. Utils.*, Order No. 888, 61 Fed. Reg. 21540, 21542 (May 10, 1996). FERC generally regulates these entities pursuant to its authority over rates and charges for wholesale sales and transmissions of electric energy. *See, e.g.,* Order No. 2000, 65 Fed. Reg. at 811. These entities, referred to here as ISOs or RTOs, perform a variety of functions, including:

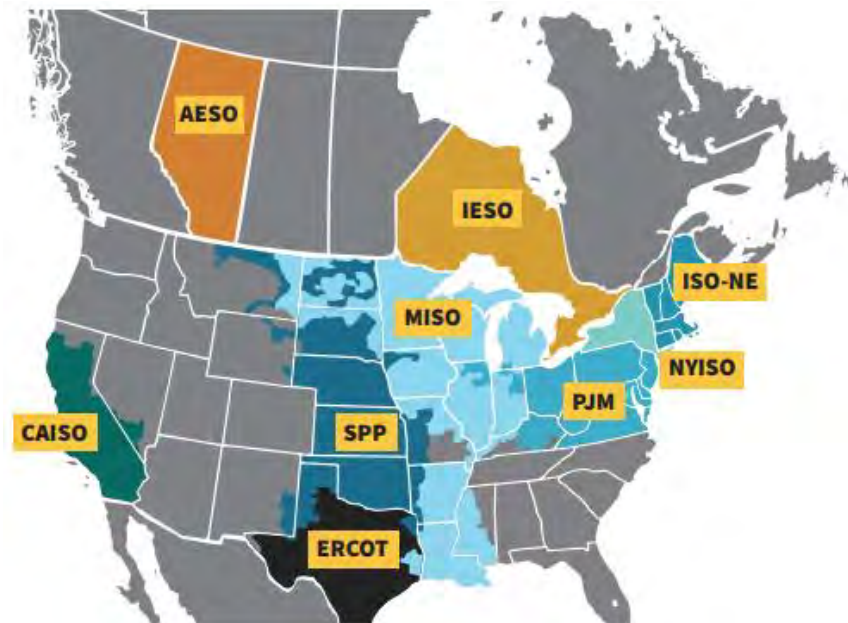
- Ensuring the electric grid operates reliably in a defined geographic footprint;
- Balancing supply and demand instantaneously and maintaining sufficient operating reserves;
- Dispatching system resources as economically as possible;

- Coordinating system dispatch with neighboring balancing authority areas;
- Planning for transmission in its footprint;
- Coordinating system development with neighboring systems and participating in regional planning efforts; and
- Providing non-discriminatory transmission access.

Ex. 46 at 53 (FERC Energy Primer). Some ISOs “also operate capacity markets, which, along with underlying resource adequacy rules, ensure sufficient capacity is available.” *Id.* at 68.

Independent System Operators now span much of the country, excluding portions of the Southeast, Southwest, and Northwest regions of the country. *See id.* at 37. The map in Figure 1 below depicts the geographic footprint of the various ISOs.

Figure 1: Boundary Areas of RTOs and ISOs

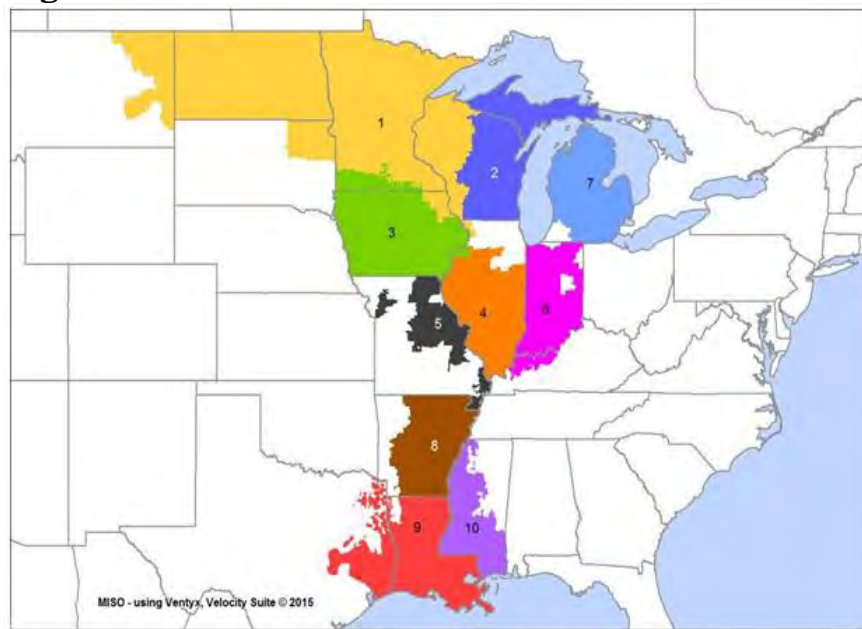


Source: Ex. 46 at 67 (FERC Energy Primer).

2. *MISO Protects Reliability and Resource Adequacy Through FERC-Regulated Reserve Margin Requirements, a Residual Capacity Auction, and Retirement Approvals.*

MISO is an Independent System Operator and the grid operator for territory stretching roughly from North Dakota to Michigan and down to Louisiana. This territory is organized into zones numbered 1 through 10, as shown in MISO’s FERC-approved tariff and reproduced in Figure 2 below.

Figure 2: MISO Local Resource Zones 1–10



Source: Ex. 75 (MISO Tariff Zonal Map).

MISO implements resource adequacy standards across its territory to ensure it achieves a level of grid reliability meeting both industry standards and those of the North American Electric Reliability Corporation (“NERC”). To meet its resource adequacy requirements, MISO utilizes a series of interrelated mechanisms that both measure current and future system needs and help the utilities in its region secure the resources that best meet those needs at least cost. *See generally* Ex. 46 at 66–75, 87–90 (FERC Energy Primer); Ex. 3 at 8–9 (EFG Report).

i. Reserve Margin Requirements.

The foundation of MISO’s resource adequacy implementation process is its Loss of Load Expectation (“LOLE”) study, which measures whether available generation capacity is capable of meeting load demand under various conditions, including low probability but high impact events (such as extreme weather). *See generally* Ex. 38 (MISO LOLE Presentation). MISO runs its LOLE study every year, based on the latest available data. It utilizes a systemic model, taking inputs from the past thirty years of weather data as well as resource performance characteristics from a broad range of operating conditions. Using this wealth of information, MISO then runs thousands of simulations looking to future years. Each of the simulations examines the system at every individual hour of each year being studied. These simulations identify circumstances that could most stress the system, while also predicting how the system’s fleet of resources will perform. *See* Ex. 58 (MISO Tariff Module E-1);

Ex. 38 (MISO LOLE Presentation); Ex. 81 at 47-54 (Joundi Testimony). MISO runs this model annually, based on the latest available data.

MISO uses its LOLE study results in conjunction with its system-wide peak demand forecast, which it develops from projections provided by each of the load-serving entities within its territory. It combines these inputs to determine how much generating capacity is required to meet MISO's industry-standard goal of expecting no more than one day with a loss of load event every ten years. *See* Ex. 10 at 2–5 (Grid Strategies June Report). The result of this calculation is a reasonable buffer of extra capacity to account for potential emergencies and other conditions, which is known as the regional Planning Reserve Margin (“Reserve Margin”). The Reserve Margin, stated as a percentage, reflects the amount of generating capacity that must be procured in each season to meet resource adequacy standards across the region. MISO develops a separate Reserve Margin for each season of the year. An illustrative calculation of a Reserve Margin is below.

Illustrative Reserve Margin Calculation

Expected Peak Demand 100,000 MW

Extra Buffer 7,000 MW

Reserve Margin 7%

After developing the system-wide Reserve Margin, MISO uses it to convert the peak demand projection for each zone into a capacity requirement (in accredited megawatts, or “MW”) that each zone must meet for each season. The requirement for each zone is known as that zone's Planning Reserve Margin Requirement (“Reserve Margin Requirement”), which is the megawatt capacity that must be procured for each zone. These megawatts can come from inside or outside the zone, so long as they are deliverable to the zone. *See* Ex. 3 at 8–9 (EFG Report).

As with the zonal calculation, MISO also converts each individual load-serving entity's projected peak demand into a capacity requirement using the system-wide Reserve Margin. A load-serving entity is, like NIPSCO and CenterPoint Indiana, an entity that “has undertaken an obligation to serve [l]oad for end-use customers by statute, franchise, regulatory requirement or contract.” *See* MISO's FERC-Approved Tariff at Module A (as currently effective), <https://etariff.ferc.gov/TariffBrowser.aspx?tid=1162> (defining “Load Serving Entity”). And the Reserve Margin Requirement for each zone is, roughly speaking, the sum of all load-serving entities' obligations in that zone.

Finally, MISO assigns to each individual resource a capacity value based on MISO's conservative estimate of how likely that generator is to be able to provide energy during peak net demand conditions. The purpose of this estimate is to determine a percentage of resources' maximum capacity (their “accredited capacity”)

that can be used by load-serving entities or in the Planning Resource Auction to achieve Reserve Margin Requirements, and it reflects that resources cannot always ensure that they will operate at their maximum possible capacity. Generally speaking, MISO’s approach combines probabilistic modeling with historic and unit-specific performance. Through the capacity accreditation process, MISO fully accounts for the limitations of each resource’s ability to contribute to MISO’s resource adequacy during peak demand conditions or during times of overall system stress (e.g., when extreme weather affects unit performance). And MISO’s capacity accreditation rules are regulated and overseen by FERC. *See, e.g., Midcontinent Indep. Sys. Op., Inc.*, 180 FERC ¶ 61,141, at P 1 (2022) (approving MISO’s seasonal resource adequacy construct); *see also Midcontinent Indep. Sys. Op., Inc.*, 189 FERC ¶ 61,065, at P 1 (2024) (approving new methodology applicable to 2028–2029 delivery year).

Once MISO (1) establishes the regional Reserve Margin, (2) converts it to a Reserve Margin Requirement for each zone using peak demand projections, (3) apportions each zone’s Reserve Margin Requirement among load-serving entities, and (4) determines all eligible resources’ accredited capacity, the load-serving entities must meet their capacity obligations. *See Ex. 3 at 8–9 (EFG Report).*

Load-serving entities have a few options for procuring capacity. First, they can use generating capacity they already own. Second, they can contract with another entity that owns generating capacity to promise to sell energy in the future when called upon by MISO to do so. Third, as a final fallback option they can obtain capacity through a residual capacity market run by MISO known as the Planning Resource Auction (“Planning Auction” or “PRA”). *See id.*

ii. MISO’s Residual Capacity Market.

MISO conducts the Planning Auction every year. The Planning Auction is actually four separate simultaneous seasonal auctions. In each auction, MISO solicits operational commitments for each season from a suite of generation resources that will ensure resource adequacy. Many resources provide an “offer” identifying what price they would need to be paid to keep operational (*i.e.*, remain capable of delivering power upon command) all or part of the resource’s accredited capacity for each of the four seasons. Other resources, including those already committed to operate via outside contracts, are self-scheduled into the auction process, meaning that MISO treats them as price takers or \$0 offers. MISO then stacks each of these resources in ascending cost order, forming a supply curve.

The supply curve crosses a preset sloped demand curve, known as the Reliability Based Demand Curve. The sloped demand curve is designed by MISO to procure a

certain amount of capacity at each price point; although it is tethered around MISO's goal of experiencing no more than one loss of load event per decade, it will obtain more capacity if it is cheaper and less if it is more expensive. This is consistent with the general principle that grid operators must always balance the tradeoff between resource adequacy and cost. *See* Ex. 10 at 2–3 (Grid Strategies June Report); Ex. 3 at 8–9 (EFG Report); Ex. 31 at 4 (MISO 2025–26 Auction Results).

The point where the supply and demand curves intersect is called the capacity market clearing price. All resources on the supply curve with offers at or below that amount are then committed to remain operational and be available for the respective season(s) in which they cleared, with the owners of those resources' capacity rights receiving the clearing price. Ex. 58 (MISO Tariff Module E-1).

iii. MISO's Approvals of Generator Retirements.

Pursuant to MISO's FERC-approved tariff, a utility within MISO seeking to suspend the operation of a generating unit must provide an "Attachment Y" notice to MISO. Ex. 60 at 1 (MISO Tariff Sec. 38.2.7); Ex. 61 (MISO Tariff Attachment Y). The purpose of the notice is to enable MISO to evaluate the potential local grid reliability impacts of such suspension. If retirement would cause unacceptable reliability impacts, MISO may offer compensation to keep the resource active as a System Support Resource. *See* Ex. 60 at PDF p. 5 (MISO Tariff Sec. 38.2.7).

3. MISO Also Continuously Monitors the Grid to Balance Supply and Demand, and to Prevent Blackouts Using an Escalating Sequence of Real-Time Alerts that Activate Reserve Resources in a Specific, Predetermined Order.

In addition to annually securing the set of resources it has determined will meet its regional reliability standard, MISO also operates the grid on a daily and hourly basis to match the resources it has available with load (*i.e.*, demand) over the course of each day. During normal operational periods, MISO uses its energy markets to receive information from every potential resource in the region (generators, batteries, etc.) about how much power they believe they can provide and at what price, and then issues instructions to the set of resources it needs to meet projected demand at least cost to the system. *See generally Elec. Power Supply Ass'n*, 577 U.S. at 268 ("Each administers a portion of the grid, providing generators with access to transmission lines and ensuring that the network conducts electricity reliably. And still more important for present purposes, each operator conducts a competitive auction to set wholesale prices for electricity. These wholesale auctions serve to balance supply and demand on a continuous basis, producing prices for electricity that reflect its value at given locations and times throughout each day." (internal citation omitted)).

On occasion, the total electric generation that is freely offered in MISO’s day-ahead market is less than the MISO region’s projected demand. That mismatch between projected demand and voluntary supply does not, however, of itself produce any disruption to the grid. In these instances, MISO implements a well-defined process to identify additional resources until the projected shortfall is addressed.

MISO has enshrined its process for securing extra resources to address projected shortfalls, which it deems “Max Gen Emergencies,” in its operational tariff. Ex. 33 at §§ 4.2–4.3 (MISO Market Capacity Emergency) (describing Max Gen Emergency Event procedures). As described there, MISO often can address any shortfall simply by issuing a capacity advisory to double check its numbers, followed by a so-called “max-gen” alert to facility operators to suspend any optional maintenance or other activities that might be interfering with resources’ power output (*i.e.*, to achieve maximum generation from all available resources). *Id.* at §§ 4.1, 4.2.2. MISO can then issue a warning of a potential shortfall and start curtailing exports and coordinating with its neighbors to bring in imports from adjacent regions. *Id.* at § 4.2.3. If these preliminary measures don’t address the shortfall, MISO will then proceed step by step through a series of five steps with subparts (labeled “1a” through “5”) of increasingly stringent mitigation measures to increase generation or reduce usage of electricity during the period at issue. Only on the final step (step “5”) does any involuntary load shedding (*i.e.*, a blackout) occur; Steps “1a” through “4b” describe an escalating sequence of mitigation measures MISO will employ, including requesting power transfers from neighboring regions, turning on backup generators, utilizing contracted demand response resources, and asking the public for voluntary reductions. *See* Ex. 33 (MISO Market Capacity Emergency); Ex. 3 at 7 (EFG Report). The following table, prepared by MISO and reproduced here as Figure 3, describes these steps (without delineating between “step 1a,” “step 1b,” etc.).³

³ The following is a partial explanation of acronyms in the table: MPs means Market Participants; LBAs means Load Balancing Authorities; AME means Available Maximum Emergency; EEA means Energy Emergency Alert; LMM means Load Management Measures; LMRs means Load Modifying Resources; EDR means Emergency Demand Response; LMPs means Locational Marginal Prices; MCPs means Market Clearing Prices; and VOLL means Value of Lost Load. Ex. 33 (MISO Market Capacity Emergency) at 2, 3, 8, 13, 19, 34.

Figure 3: Market Capacity Emergency Procedure Steps



Source: Ex. 33 at 43 (MISO Market Capacity Emergency).

Through a combination of responsible grid management and capacity retention policies, MISO has avoided the need to utilize the full five steps of its emergency process in recent years. MISO has not faced a Market Footprint Maximum Generation Emergency Event Step of 3 or higher since 2009, according to the most recent summation available (through June 2024)—and the highest Max Gen event in the recent Summer 2025 season reached only Step 1b. *See* Ex. 32 at 4–27 (MISO Emergency Declarations); Ex. 68 at 3–4 (Grid Strategies Sept. Report). For the Fall 2025 season that recently concluded, PIOs are not aware of any EEA alert having been issued. Moreover, MISO Staff’s December 2025 presentation to MISO’s Board of Directors indicated that “No reliability actions were needed this fall” and showed on a granular daily level that no alerts, warnings, or reliability actions or events occurred in the Fall 2025 season. Ex. 138 at 11 (MISO Fall 2025 Operations Report).

For the recently concluded Winter 2025–2026 season, MISO avoided the need to utilize any Max Gen event beyond Step 2c, even during Winter Storm Fern in the latter part of January. Even during the storm’s most challenging hours, MISO had more than 5,000 MW of surplus generation above the level needed to serve the system load. Ex. 173 at 5 (Konidena April Declaration) (showing surplus generation in table 3); *id* at 4 (describing how the listed values “represent a floor on the potential amount of resources available to MISO.”). Winter Storm Fern constitutes

the latest demonstration that MISO's Maximum Generation procedures can secure additional operating capacity when needed to meet load.

4. Indiana Evaluates Resource Adequacy Through Integrated Resource Planning and Annual Capacity Procurement Requirements.

Electric utilities in Indiana are required, pursuant to legislation enacted over a decade ago, to submit to the Indiana Utility Regulatory Commission (the "Indiana Commission") an "integrated resource plan that assesses a variety of demand side management and supply side resources to meet future customer electricity service needs in a cost effective and reliable manner." Ind. Code § 8-1-8.5-3(e)(2). By rule, the Indiana Commission requires utilities—including NIPSCO and CenterPoint Indiana—to submit their IRP for review every three years. 170 IAC 4-7-2(a). Following submission of the IRP, customers and interested parties may submit comments to the Indiana Commission; this is followed by a draft report issued by the Indiana Commission's designated director, another round of stakeholder comment, and then a final report from the Indiana Commission's designated director. The director's report is to comment on the IRP's compliance with requirements for its contents. 170 IAC 4-7-2.2(a)–(g).

And those required contents are extensive. A utility's integrated resource plan must include the following, among other requirements:⁴

- (1) At least a twenty-year future period for predicted or forecasted analyses;
- (2) An analysis of historical and forecasted levels of peak demand and energy usage, including historical load shapes, actual and weather-normalized energy and demand levels; assumptions as to demographic, economic, and technological changes;
- (3) At least three alternative forecasts of peak demand and energy usage;
- (4) A description of the utility's existing resources, including expected retirements, deratings, life extensions, repowerings, and refurbishments; fuel price forecasts by generating unit; and analysis of the transmission system's effects on power supply;

⁴ The following partial description of requirements is condensed slightly from the language used in Indiana's regulatory code.

(5) A description of the utility's process for selecting possible alternative future resources for meeting future demand, including a cost-benefit analysis, if performed;

(6) A description of the possible alternative future resources for meeting future demand, including demand-side, supply-side, and transmission resources;

(7) . . .

(8) A description of candidate resource portfolios and the process for developing those portfolios, including how the candidate portfolios performed across a wide range of scenarios, and the cost of each portfolio;

(9) A description of the utility's preferred resource portfolio, including a description of how the preferred resource portfolio balances cost effectiveness, reliability, and portfolio risk and uncertainty;

(10) A short-term action plan for the next three-year period to implement the utility's preferred resource portfolio and its workable strategy, including an implementation schedule and budget;

(11) A discussion of inputs, methods, and definitions used in the IRP;

(12) Appendices of data sets and sources used in the IRP;

(13) A description of the utility's effort to develop and maintain a database of electricity consumption patterns, disaggregated by several classes of users;

(14) . . .

(15) A proposed schedule for industrial, commercial, and residential customer surveys;

(16) A discussion of the use of advanced metering infrastructure for enhancing usage data and improving load forecasts, DSM programs, and other aspects of planning;

(17) . . .

(18) A discussion of distributed generation and its effect on planning;

(19) . . .

(20) A discussion of how the utility's fuel inventory and procurement planning practices have been taken into account;

(21) . . .

(22) A description of the generation expansion planning criteria;

(23) A discussion of how compliance costs for existing or reasonably anticipated air, land, or water environmental regulations impacting generation assets have been taken into account;

(24) A discussion of how the utilities balanced resource planning objectives including cost effectiveness, rate impacts, risks, and uncertainty;

(25) A description of the base case scenario;

(26) A description and analysis of alternative scenarios;

(27) A brief description of transmission modeling in the Indiana system;

(29) An explanation of the avoided cost calculation for demand side resources;

(30) A summary of the utility's most recent public advisory process.

170 IAC 4-7-4 to 4-7-9; *see also* Ex. 3 at 1 (EFG Report).

While the Indiana Commission does not directly approve or reject the utility's integrated resource plan (beyond the director's reports described above), any action an Indiana utility takes that impacts its generation mix, including applying for a Certificate of Public Convenience and Necessity for a generating resource, must be consistent with its most recently submitted IRP, unless differences between the most recent IRP and the resource action are fully explained and justified with supporting evidence. Ind. Code § 8-1-8.5-5(b)(2)(B); 170 IAC 4-7-2.5(b). Thus, IRPs are stable and consequential utility planning documents that are given considerable scrutiny by the Indiana Commission.

In addition to submitting IRP analyses, electric utilities located within Indiana's MISO transmission area are required to pass on to the Indiana Commission their annual planning reserve margin report submitted to MISO. Utilities are also required to submit their annual resource adequacy assessment to the Indiana Commission within twenty-five days of submitting the report to MISO. 170 IAC 4-7-2.3(a). Additionally, an electric utility in Indiana is required to demonstrate annually to the Indiana Commission that for both the Summer and Winter seasons, no more than 15% of its allocated capacity requirement will be acquired from the relevant RTO capacity auction. In other words, each utility must demonstrate that it either owns or has under contract 85% of its capacity requirement. Ind. Code § 8-1-8.5-13.

5. NERC Protects Reliability via Standards and Regular Assessments.

NERC is the “Electric Reliability Organization” under Section 215 of the Federal Power Act. *N. Am. Elec. Reliab. Corp.*, 116 FERC ¶ 61,062, at P 3, *order on reh’g & compliance*, 117 FERC ¶ 61,126 (2006); *see* 16 U.S.C. § 824o(a)(2). This role dates back to 2005, after Congress added Section 215 to the Act and FERC certified NERC as the Electric Reliability Organization. Energy Policy Act of 2005, Pub. L. No 109-58, Title XII, Subtitle A, section 1211(a), 119 Stat. 594, 941 (2005), 16 U.S.C. § 824o (2000 & Supp. V 2005); 116 FERC ¶ 61,062, at P 16.

As the Electric Reliability Organization, NERC is responsible for establishing and enforcing reliability standards for the bulk power system. 16 U.S.C. § 824o(a)(2); 18 C.F.R. § 39.1. NERC’s reliability standards are subject to FERC’s review and approval. 16 U.S.C. § 824o(d); Ex. 10 at 7 (Grid Strategies June Report).

The NERC-developed and FERC-approved reliability standards apply to all users, owners, and operators of the bulk power system within the continental United States. 16 U.S.C. § 824o(b)(1); 18 C.F.R. §§ 39.2, 40.1(a), 40.2(a); *see* 18 C.F.R. § 39.1 (defining “Bulk-Power System”). Each reliability standard identifies the types of entities that must comply with the standard, such as generator owners, transmission owners, or transmission operators. *Reliability Standard Compliance and Enforcement in Regions with Regional Transm. Orgs. or Indep. Sys. Ops.*, 122 FERC ¶ 61,247, at P 4 (2008); *e.g.*, Ex. 130 (NERC Emergency Ops., EOP-011-4) (stating requirements applicable to, *inter alia*, balancing authorities, reliability coordinators, and transmission operators for the purpose of “address[ing] the effects of operating Emergencies by ensuring each Transmission Operator and Balancing Authority has developed plan(s) to mitigate operating Emergencies and that those plans are implemented and coordinated within the Reliability Coordinator Area as specified within the requirements”). Independent System Operators like MISO must comply with applicable NERC standards, and they are subject to penalties for noncompliance. 122 FERC ¶ 61,247, at PP 1, 5, 16; *see also* MISO Tariff Schedule 34 (setting forth allocation costs associated with monetary penalties assessed against MISO for violation of NERC standards).

NERC performs other functions in addition to development and enforcement of reliability standards. For instance, NERC annually assesses seasonal and long-term reliability of the bulk power system and monitors system performance. *See* Ex. 10 at 7–8 (Grid Strategies June Report); 18 C.F.R. § 39.11. As part of these assessments, an “elevated risk” designation does not constitute an emergency because it does not indicate the possibility of imminent shortfalls; indeed, it is only the second of three risk levels offered by NERC. NERC typically provides specific context and details associated with its determination. Since it began providing standardized “risk”

assessments by region in the summer of 2021, NERC has adhered to a three-tiered assessment of risk: areas facing the least risk are “low” or “normal” risk regions, areas facing the most risk are “high” risk regions, and areas in between are “elevated” risk regions. *See* Exs. 42A at PDF pp. 74–75, 42B at pp. 35 & 81, 42C at p. 42 (2019–24 NERC Summer Reliability Assessments). The details of the three risk levels are explained further below in Figure 4. NERC’s determination of “elevated” risk generally indicates that there is a “[p]otential for insufficient operating reserves in above-normal conditions.” Ex. 41 at 6 (NERC 2025 Summer Reliability Assessment). An “elevated risk” does not justify an emergency declaration because it does not indicate the possibility of imminent shortfalls; indeed, it is only the second of three risk levels offered by NERC. Moreover, Planning Reserve Margins *do generally* meet Reference Margin Levels in “elevated” risk regions. *Id.* at 10, 41. NERC typically provides specific context, assumptions, and details associated with a determination to allow an audience to understand its implication. *See id.* at 16.

Figure 4: NERC Seasonal Risk Assessment Levels

Table 2: Seasonal Risk Assessment Summary	
Category	Criteria ¹
High Potential for insufficient operating reserves in normal peak conditions	- Planning Reserve Margins do not meet Reference Margin Levels (RML); or - Probabilistic indices exceed benchmarks, e.g., loss of load hours (LOLH) of 2.4 hours over the season; or - Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under normal peak-day demand and outage scenarios²
Elevated Potential for insufficient operating reserves in above-normal conditions	- Probabilistic indices are low but not negligible (e.g., LOLH above 0.1 hours over the season); or - Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under extreme peak-day demand with normal resource scenarios (i.e., typical or expected outage and derate scenarios for conditions);² or - Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under normal peak-day demand with reduced resources (i.e., extreme outage and derate scenarios)³
Normal Sufficient operating reserves expected	- Probabilistic indices are negligible - Analysis of the risk hour(s) indicates resources will be sufficient to meet operating reserves under normal and extreme peak-day demand and outage scenarios⁴
Table Notes: ¹ The table provides general criteria. Other factors may influence a higher or lower risk assessment. ² Normal resource scenarios include planned and typical forced outages as well as outages and derates that are closely correlated to the extreme peak demand. ³ Reduced resource scenarios include planned and typical forced outages and low-likelihood resource scenarios, such as extreme low-wind scenarios, low-hydro scenarios during drought years, or high thermal outages when such a scenario is warranted. ⁴ Even in normal risk assessment areas, extreme demand and extreme outage scenarios that are not closely linked may indicate risk of operating reserve shortfall.	

Source: Ex. 143 at 11 (NERC 2025–2026 Winter Reliability Assessment).

B. The Evidence Shows No Reliability or Resource Adequacy Crisis in MISO for Spring 2026, Summer 2026, or Thereafter.

1. There Is No Evidence of a Resource Adequacy Crisis in the current Spring or upcoming Summer Seasons.

MISO conducted its annual four-season capacity auction (the Planning Auction, discussed above in sec. IV.A.2) as scheduled in the spring of 2025. The 2025–2026 Planning Auction procured adequate supplies for MISO as a whole and for Local Resource Zone 6 (which includes the MISO portion of Indiana⁵) for the Spring 2026 season.⁶ Notably, the 2025–2026 auction did not include Schahfer or Culley 2 as capacity resources for the Spring 2026 season. Ex. 11 at PDF p. 4 (NIPSCO 2025 Planning Reserve Margin Report); Ex. 12 at 4 (CenterPoint 2025 Planning Reserve Margin Report). For the Spring 2026 period, cleared offers from Zone 6 totaled 15,181.0 megawatts, which exceeded the Zone 6 Local Clearing Requirement by over 46 percent. The Planning Auction calculated that surplus capacity from other areas of MISO could provide adequate imports—2,985.6 megawatts—towards meeting Zone 6’s Reserve Margin Requirement for Spring. Ex. 31 at 21 (MISO 2025–2026 Planning Auction Results); Ex. 3 at 7 (EFG Report).

In addition to Zone 6 fully meeting its capacity requirements, every other Local Resource Zone in MISO successfully met its capacity requirements within the 2025–2026 Planning Auction, resulting in MISO finding that there were no capacity deficits in the region during the planning year. See Ex. 31 at 12 (MISO 2025–26 Auction Results) (“The 2025 PRA demonstrated sufficient capacity at the regional, subregional and zonal levels”); Ex. 34 at 9 (Ramey MISO Comments) (testifying just after the 2025–2026 Planning Auction that no capacity deficits for the period beginning in 2025 materialized).

As of the date of this Request for Rehearing, MISO had not yet published the results of its 2026–2027 Planning Auction (covering the year beginning June 1, 2026), which accepted offers last month (March 26 through March 31) and is expected to announce results on April 28, 2026 (that is, next week). Ex. 170 at 5, 6

⁵ MISO Local Resource Zone 6 includes most of Indiana, including the CenterPoint Indiana and NIPSCO service territories, and a portion of Kentucky. See Ex. 75 (MISO Tariff Zonal Map).

⁶ MISO defines the Spring season for its Planning Auction as March through May, and defines the Summer season as June through August.

(MISO 2026–2027 Planning Auction Timeline). Due to the statutory deadline for this filing, PIOs are not able to describe how the 2026–2027 Planning Auction accounted for resource adequacy in MISO’s Summer 2026 season. However, although MISO has not yet divulged those results, MISO is not projecting any possibility of a regional resource adequacy shortfall for Summer 2026. MISO’s joint annual survey with the Organization of MISO States (“OMS”), which forecasts generation capacity supply and system load (the “OMS-MISO Survey”), evaluates a range of potential outcomes years into the future, using a set of assumptions ranging from extremely conservative to a match of utility projections. *See supra* sec. IV.A.2. The most recent edition of that survey, completed June 2025, predicts a *surplus* of between 1.4 and 6.1 gigawatts for the Summer 2026 season. Ex. 89 at 2 (2025 OMS-MISO Survey)

As required by Indiana law, both NIPSCO and CenterPoint Indiana completed their triennial IRP analysis within the past sixteen months: NIPSCO in December 2024 and CenterPoint Indiana in December 2025. Exs. 100A–100C (NIPSCO 2024 IRP); Ex. 21 (CenterPoint Indiana 2025 IRP). NIPSCO’s 2024 IRP assumed that Schahfer Units 17 and 18 would retire at the end of 2025, with reliability maintained through previously approved transmission upgrades and approximately 2,100 MW of replacement resources (renewables plus a new 400-MW gas peaker) entering service. Ex. 100A at 6–7 (NIPSCO 2024 IRP, part 1); Ex. 3 at 3–4 (EFG Report). NIPSCO’s resource planning analysis indicated no sign of a Summer reliability shortfall in 2026, and the retirement of Schahfer would not create a capacity deficiency under the current rules. Ex. 100A at 26 (NIPSCO 2024 IRP, part 1); Ex. 3 at 4–5 (EFG Report). NIPSCO’s analysis also showed that for the Summer 2026 season, total accredited capacity is well above the Planning Reserve Margin. Ex. 100A at 26 (NIPSCO 2024 IRP, part 1); Ex. 3 at 5–6 (EFG Report). Thus, the IRP record supports the conclusion that continued operation of Schahfer 17 and 18 is not required for resource adequacy in early 2026. Ex. 3 at 5–6 (EFG Report). NIPSCO also submitted a Planning Reserve Margin Annual Report to the Indiana Commission last year to demonstrate how it meets the 85% threshold for each season of 2025–2026 and 2026–2027 pursuant to Ind. Code § 8-1-8.5-13(*l*), as discussed above in section IV.A.4. Ex. 11 at 3–6 (NIPSCO Planning Reserve Margin 2025 Report).

Similarly, CenterPoint Indiana’s most recent IRP, filed late last year, assumes Culley Unit 2 would retire at the end of 2025 as part of its Reference Case. Ex. 21 at 151 (CenterPoint Indiana 2025 IRP). CenterPoint Indiana’s analysis and projections show no capacity shortage in Summer 2026 or in subsequent years. *Id.* at 152; Ex. 3 at 3 (EFG Report). Specifically, for the Summer 2026 season, CenterPoint Indiana projected a capacity surplus of 58 MW relative to its Planning Reserve Margin. *Id.* Additionally, CenterPoint Indiana submitted its Planning Reserve Margin Annual

Report to the Indiana Commission in May 2025, again pursuant to Ind. Code § 8-1-8.5-13(l). The report showed that CenterPoint Indiana more than meets its minimum 85% requirement of owned or contracted resources, with 99% of the utility's allocated Reserve Margin Requirement for Spring 2026 and 106% for Summer 2026 owned or contracted for. Ex. 12 at 4–5 (CenterPoint 2025 Planning Reserve Margin Report).

2. There Is No Evidence of a Resource Adequacy Crisis After Summer 2026.

The MISO system is also positioned to operate reliably for years beyond the 90-day timeframe of the Orders. There is ample evidence demonstrating that this is true for the remainder of the 2025–2026 planning year; for the next couple years after that; and even out through the 2030 time horizon that the Department identifies as a long-term source of concern.

First and most directly, MISO has secured the stability of its grid through at least the end of May 2026 by operation of its 2025–2026 Planning Auction. The auction secures in April of each year the resources necessary to ensure grid reliability individually for each of the four subsequent seasons. *See supra* sec. IV.A.2.ii. The 2025–2026 Planning Auction exceeded its target Reserve Margin Requirements for the Spring season by 1.5%, meaning that (as it did for the Summer, Fall, and Winter seasons) MISO will enter the Spring season with *more* resources than its own analysis has indicated are actually needed to ensure grid reliability. Ex. 31 at 5 (MISO 2025–26 Auction Results). Furthermore, MISO's modeling in conjunction with its shift to a seasonal resource adequacy construct indicated that the loss of load risk in Spring (as with Fall 2025 and Winter 2025–2026) is very low. Ex. 81 at 49:15–17 (Joundi Testimony); *see also* Ex. 82 at 33 (MISO 2024–25 LOLE Study Report); Ex. 83 at 34 (MISO 2025–26 LOLE Study Report). Thus, there is no basis for any resource adequacy concern for the Spring season.

Second, although MISO has not yet reported the results of its 2026–2027 Planning Auction (or the auctions for subsequent years), MISO is not projecting any possibility of a regional resource adequacy shortfall through May 2027. The 2025 OMS-MISO Survey, discussed in *supra* section IV.A.2, includes projections for Planning Year 2027–2028 ranging from a surplus of 6.4 GWs to a small deficit of 1.4 GWs. Ex. 89 at 7 (2025 OMS-MISO Survey). In other words, the survey provides no basis for any concern about MISO's ability to meet resource adequacy needs through at least May 2027. And a series of unlikely events would have to occur for the region to see even a minor (1–2 GW) deficit through May 2028, as further explained below. MISO's system is robust, and even before its new approach to

generator interconnection (also discussed below), it was on track as of early June 2025 to ensure that its grid remains robust for approximately the next three years.

The evidence also confirms sufficient resources in the months and years after Summer 2026 in the utility territories of both NIPSCO and CenterPoint Indiana, where the subject generating Plants are located. CenterPoint Indiana's Planning Reserve Margin Report submitted to the Indiana Commission last year shows that it has secured accredited resources totaling over 100% of its allocated Reserve Margin Requirement in each season of planning year 2026–2027 and 2027–2028. Ex. 12 at PDF pp. 5–6 (CenterPoint 2025 Planning Reserve Margin Report). And NIPSCO's IRP "indicates no sign of a summer reliability shortfall in . . . 2027 [in addition to 2026]." Ex. 3 at 5 (EFG Report).

To the extent there are capacity gaps shown in the NIPSCO and CenterPoint Indiana IRPs in years 2028 and beyond, such gaps are not *predictions* of the shortage of capacity needed to meet demand. Rather, consistent with the planning purpose of IRPs, both NIPSCO and CenterPoint Indiana's IRPs calculate the amount of accredited capacity needed to meet demand, plus, maintain a Reserve Margin as determined by MISO. Ex. 21 at 81 (CenterPoint Indiana 2025 IRP); Ex. 100A at 24 (NIPSCO 2024 IRP, part 1). Any "surplus" or "shortfall" shows whether the utility has more or fewer resources than are needed to achieve MISO's Reserve Margin given expected future load and utility-owned generation and capacity purchases.

For Summer 2028 and Summer 2029, CenterPoint Indiana shows a capacity shortfall of 115 MW and 114 MW respectively. Ex. 21 at 152 (CenterPoint Indiana 2025 IRP). NIPSCO shows a shortfall starting in Summer 2028. Ex. 100A at 26 (NIPSCO 2024 IRP, part 1). But these projected capacity deficits are not a basis on which to declare an imminent shortfall or an emergency. They are a planning signal to guide medium- and long-term utility planning. And they are being treated as such by CenterPoint Indiana and NIPSCO. CenterPoint Indiana does not have a projected shortfall in 2028 because it is unable to procure or interconnect enough capacity. Rather, the utility has not decided on whether to purchase capacity from the MISO market or construct a battery using Culley 2's interconnection rights and is conducting an RFP to see which would be more cost-effective for its customers. *See* Ex. 21 at 190 (CenterPoint Indiana 2025 IRP); Ex. 3 at 3 (EFG Report). Likewise, NIPSCO's existing capacity projection showing a shortfall starting in 2028 should be understood as a "foundational starting point" upon which "NIPSCO developed six different portfolio concepts around accreditation and emission intensity through least cost portfolio optimization analysis." Ex. 100A at 26 (NIPSCO 2024 IRP, part 1); *see also* Ex. 100A at 1 (describing NIPSCO's selected solution of "add[ing] between 900 and 1,150 MW of new storage capacity and 350

MW of short-term thermal PPAs by 2028-2029. . . . NIPSCO will continue to track accreditation trends as the rule is implemented and adjust its storage procurement plan accordingly.”) (NIPSCO 2024 IRP). The capacity supply-demand balance graphs in NIPSCO’s IRP “are NIPSCO’s going-in position to its 2024 IRP (including existing and planned resources) and do not contemplate unidentified, additional resources that NIPSCO would plan to acquire as a result of its IRP to fill gaps in need in 2028 and beyond.” Ex. 3 at 5 (EFG Report) (referring to Ex. 100A at 26 (NIPSCO 2024 IRP, part 1)).

Third, although MISO has spoken publicly about its long-term resource adequacy concerns heading into Summer 2028 and beyond, those concerns can be addressed through traditional, non-emergency, policy measures and other strategies to ensure no shortfall actually occurs. And MISO is not standing still in this regard; as MISO has explained,

“State regulators along with utilities have the responsibility of ensuring resource adequacy. MISO remains focused on reliably operating the grid using the resources our members provide, while working closely with stakeholders and regulatory partners, providing visibility into system needs and sending market signals to inform long-term resource planning.”

Ex. 117 at PDF p. 4 (RTO Insider Article).

Generally speaking, from FERC down to stakeholders, everyone working regularly in the energy regulatory world recognizes that the industry is dynamic, and everyone is engaging to ensure there are adequate resources going forward. At the end of May 2025, FERC hosted a technical conference where MISO, the MISO Independent Market Monitor, and other contributors highlighted that the system is in good shape today, and outlined plans to ensure that remains the case down the road. *See, e.g.*, Ex. 35 at 1 (Patton MISO Comments) (“The resource adequacy challenges and risks in MISO are not nearly daunting as portrayed by MISO planning reports or the NERC 2024 Long-Term Reliability Assessment.”); *see also* Ex. 62 at 13 (FERC Technical Conference Notice).

In fact, MISO has already taken tangible steps to address what it perceived to be a potential for resource adequacy shortfalls down the road: it developed, and secured FERC approval for, an Expedited Resource Addition Study (ERAS) pathway for generator interconnection. *See generally* Ex. 90 (MISO ERAS Transmittal Letter); Ex. 91 at P 1 (MISO ERAS Decision). The ERAS proceeding demonstrates that in response to somewhat conjectural resource adequacy shortfall projections, MISO launched an entirely new interconnection process that is currently underway. ERAS has already accepted, in its first three cycles, forty

projects totaling around 19,000 megawatts of new capacity, most of which will be provided by gas plants. *See* Ex. 171 (MISO ERAS March Release); Ex. 172 at 1–3 (ERAS Interconnection Requests). *See also* Ex. 48 at PDF p. 2 (Utility Dive, MISO begins reviewing 6.1 GW — 70% of it gas — in fast-track interconnection study). These projects will receive fast-tracked interconnection studies, with projected in-service dates no later than three years from now. Including the forty projects already accepted, projects totaling nearly 27,000 megawatts have been accepted or are pending validation into the ERAS study program. Ex. 171 at PDF p. 2 (MISO ERAS March Release). Of the first twenty-five projects in the program, accepted in September and December of last year, at least ten have already executed interconnection agreements and fifteen more were nearing completion, as of last month. Ex. 171 at PDF p. 2 (MISO ERAS March Release). That approximately 27 GW of nameplate capacity by itself would more than cover the OMS-MISO Survey’s maximum projected needs under the most conservative assumptions.⁷ The OMS-MISO Survey did not account for ERAS projects because it predated FERC’s approval of ERAS. Thus, MISO does not simply have a plan to address the possibility of shortfalls three-plus years down the road; actually, a key pillar of its plan is already underway.

Nor has Winter Storm Fern called into question MISO’s resource adequacy—during possible future extreme winter conditions or in any other season. During the tightest operational hour of Fern on January 24, 2026, MISO had access to at least 5,070 MW more generation than was needed to meet MISO’s peak load plus operating reserve requirements. Ex. 173 at 5 (Konidena April Declaration); *id.* at 4 (explaining why the calculated numbers represent a “conservative” “floor on the potential amount of resources available to MISO”). Even assuming Schahfer Unit 17, Culley Unit 2, and Campbell were running at their maximum capacities during Fern for a combined total capacity of just under 2,000 MW, MISO still would have had more than 3,000 MW of excess capacity available to it. Ex. 158 at 1 (March Schahfer Order) (noting a Unit 17 nameplate capacity of 423.5 MW); Ex. 159 at 3 (March Culley Order) (noting a Unit 2 nameplate capacity of 103.7 MW); Ex. 165 at 1 (February 2026 Campbell Order) (noting a nameplate capacity of 1,420 MW). The

⁷ While the 27 GW of capacity is nameplate capacity, not accredited capacity, the accredited capacity of the produced resources will almost certainly exceed the 1.4 GW capacity gap identified in the OMS-MISO survey. For combined cycle turbines, accredited capacity is, on average, between 84.7% and 91.4% of the generator’s nameplate capacity. *See* Ex. 47 (MISO Schedule 53 Class Averages). Gas generation is 75% by size of the current ERAS queue, including selected and pending applicants. Ex. 172 (ERAS Interconnection Requests).).

Department thus provides no basis for its statements in the Orders that Winter Storm Fern “demonstrated” “MISO’s resource adequacy concerns.” Ex. 158 at 3 (March Schahfer Order); Ex. 159 at 3 (March Culley Order). *See generally* Ex. 173 at 8 (Konidena April Declaration). And the record does not support that the Plants would have been able to solve any resource adequacy concerns during Winter Storm Fern even if there were not enough capacity. For instance, as CenterPoint Indiana noted, Culley’s “performance during the recent MISO cold weather event underscores a pattern of unreliability of [Culley Unit 2],” and Culley was forced offline for at least one day during Fern. Ex. 169 at 2 (CenterPoint Letter to USDOE). Rather, the record shows that MISO did not need the capacity provided by plants subject to 202(c) orders during even the most extreme hours of Fern.

Indeed, while in the throes of Winter Storm Fern, MISO assured FERC on January 26, 2026 that “existing processes have cleared sufficient electric generating capacity across MISO for the periods of time covered by the Order.” Ex. 181 at 2 (MISO January Filing). Additionally, while the Department apparently received twenty different requests from utilities and transmission grid operators for Section 202(c) orders during Winter Storm Fern, MISO apparently did not submit any such application, and the Department issued no order during that time period directed to MISO. Ex. 182 (2026 DOE 202(c) Orders Webpage). There is no evidence that pre-existing orders under Section 202(c) were needed to meet MISO’s resource need during this Winter Storm Fern time period. And MISO’s monthly Operations Report stated that “[r]eliability, markets[,] and operational functions performed as expected in January.” Ex. 183 at 2 (MISO January Operations Report).

C. Schahfer and Culley Should Retire As Soon As Possible.

1. Schahfer and Culley Were Built Four to Six Decades Ago.

i. Schahfer Units 17 and 18 Are Electric Generating Units in Indiana Originally Built in the Mid-1980s.

The R.M. Schahfer Generating Station is a coal and gas-burning power plant in Wheatfield, Indiana, owned and operated by NIPSCO, the retail electric utility that serves portions of northwest Indiana. Four coal-burning units were commissioned at the Schahfer site between 1976 and 1986: Units 14, 15, 17, and 18. Coal is delivered to Schahfer by rail. Two smaller gas combustion turbines, Units 16A and 16B, were commissioned in 1979. The Indiana Commission has approved NIPSCO’s plan to install new combustion turbine gas units at the site upon the retirement of Units 17 and 18, using the retiring units’ interconnection rights. *See* Ex. 20 (IURC Schahfer Gas Plant Order); Ex. 132 (NIPSCO Rate Case Discovery Responses).

NIPSCO is a member of MISO and offers the output of the Schahfer coal units in the MISO energy markets. In its 2018 IRP, NIPSCO determined that retiring and replacing all four Schahfer units would reduce costs for its customers. Ex. 71 at 6-7 (NIPSCO 2018 IRP). The two largest of the four original Schahfer units were retired in 2021. Ex. 72A at 9 (NIPSCO 2021 IRP, part 1). The remaining Schahfer coal units, Units 17 and 18, were slated to retire in December 2025. Ex. 102 (MISO Attachment Y Response to NIPSCO).

The Schahfer coal units are no longer competitive in the MISO energy market and have exhibited a long-term decline in generation over the last two decades. *See infra* sec. IV.C.3. Due to their lack of economic competitiveness, NIPSCO has planned and executed a decade-long process to replace these aging coal units with modern generation units.

ii. Culley Unit 2 Is an Electric Generating Unit in Indiana Built in 1966.

The F.B. Culley Generating Station is a coal-burning power plant located in Warrick County, Indiana, near Newburgh. It is owned and operated by CenterPoint Energy Indiana South (formerly Southern Indiana Gas & Electric Company) and sits on the north bank of the Ohio River. CenterPoint Energy Indiana South is the retail electric utility that serves southwest Indiana. Three coal-burning units were built at the Culley facility between 1955 and 1973: Units 1, 2, and 3. Unit 1 has retired.

2. The Owners of Schahfer and Culley 2 Are Investor-Owned Utilities Subject to Extensive Regulation.

i. R.M. Schahfer Generating Station Is Owned by Northern Indiana Public Service Company LLC.

NIPSCO has owned the Schahfer plant since it was built in the 1980s. NIPSCO is a subsidiary of NiSource Inc., a publicly traded corporation based in Indiana with subsidiary utilities in five other states. Ex. 78 at 15, 19, 23 (NiSource 2024 Annual Report). NIPSCO qualifies as a “public utility” under Indiana law, rendering it subject to extensive regulation of its operations by the Indiana Commission: *see, e.g.*, Ind. Code § 8-1-2-1(a), ch. 8-1-2, ch. 8-1-8.5. NIPSCO owns several generating plants in Indiana, including the Michigan City Unit 12 coal generating plant with a capacity of 455 megawatts, the Sugar Creek Generating Station combined-cycle gas plant with a capacity of 563 megawatts, and numerous wind and solar generating facilities around the state of Indiana (plus one solar facility in Kentucky). Ex. 100A at 7 (NIPSCO 2024 IRP, part 1). NIPSCO is also constructing a 400 MW gas combustion turbine facility at the site of Schahfer Units 17 and 18, as discussed below in section IV.C.4.i. NIPSCO is subject to the Indiana Commission’s triennial

integrated resource planning requirement and submitted its most-recent IRP to the Indiana Commission in December 2024. 170 IAC 4-7-2(a)(3)(C); Exs. 100A–100C (NIPSCO 2024 IRP).

ii. Culley Unit 2 Is Owned by CenterPoint Energy Indiana South.

The F.B. Culley Generating Station is owned by CenterPoint Energy Indiana South (CenterPoint Indiana), which is a subsidiary of CenterPoint Energy, Inc., a publicly traded corporation based in Houston, Texas with subsidiary electric and gas utilities in four states including Indiana. Ex. 79 at 19-20 (CenterPoint 2024 Annual Report). Like NIPSCO, CenterPoint Indiana qualifies as a “public utility” under Indiana Code § 8-1-2-1, rendering it subject to the state’s comprehensive utility regulatory scheme. CenterPoint Indiana owns or controls several generating assets in Indiana, including the two Culley coal units totaling 360 MW; gas turbines totaling 620 MW at A.B. Brown; and hundreds of megawatts worth of owned or contracted wind and solar generating assets. Ex. 80 at 13 (CenterPoint 2025 IRP Summary). Culley Unit 2 is the only CenterPoint Indiana coal unit that lacks post-combustion pollution controls for nitrogen oxides. Ex. 115 at 162-163 (Vectren⁸ 2020 IRP). CenterPoint Indiana is also subject to the Indiana Commission’s triennial integrated resource planning requirement and submitted its most-recent IRP to the Indiana Commission in December 2025. 170 IAC 4-7-2(a)(3)(C); Ex. 21 (CenterPoint Indiana 2025 IRP).

3. Schahfer and Culley 2 Are Old, Unreliable, Inflexible, Dirty, and Expensive.

i. Schahfer Exemplifies these Unwanted Attributes.

a. Schahfer Is Old and Unreliable.

Schahfer Units 17 and 18 are 43 and 40 years old, respectively, beyond the typical economic design life of 40 years for a coal unit, and approaching the end of the typical operational life of coal units (40 to 50 years). Ex. 4 at 7 (Powers January Decl.) (citing Ex. 63 (Palgrave Handbook) and Ex. 64 (IEA Report)). Both units have experienced long and recurrent outages in recent years that reflect aged, worn components that are expensive and may be difficult to repair or replace. *Id.* at 7–8; Ex. 132 at PDF p. 16 (NIPSCO Rate Case Discovery Responses) (“NIPSCO calculates that operating Schahfer Units 17 and 18 beyond 2025 would require more than \$1 billion of additional investment through 2027.”). In the tables below, and

⁸ CenterPoint Energy Indiana South was formerly known by the trade name Vectren South or Vectren.

with further context in his declaration, PIOs’ expert engineer Bill Powers identifies the duration and reasons for the units’ longest outages in the past two years based on NIPSCO’s filings with the Indiana Commission. Ex. 4 at 7–8 (Powers January Decl.). For reference, there are 8,760 hours in a year.

Longest 2025 Outages by Type

Unit	Outage Description	Total Duration (hours)
17	• Boiler tube leaks (5 outages)	1,044
	• Water level alarm	74
18	• Boiler tube leak (1 outage)	150
	• Steam turbine bearing vibration / failure	4,205
	• High turbine bearing vibration	1,996

The numbers above are rounded to the nearest hour.

Longest 2024 Outages by Type

Unit	Outage Description	Total Duration (hours)
17	• Boiler tube leaks (2 outages)	1,645
18	• ESP problems (1 outage)	147
	• Boiler tube leaks (3 outages)	159
	• Pulverizer mill trip, extensive damage	614

The numbers above are rounded to the nearest hour.

Ex. 4 at 6 (Powers January Declaration) (citing NIPSCO public filings including Exs. 14–16 (Saffran Q1, Q2, Q3 2025 Outage Testimony)); Ex. 174 at 7 (Saffran Q4 2025 Outage Testimony).

These outages demonstrate Schahfer’s increasing inability to consistently perform even under normal conditions, let alone to meet an emergency. Both units have been unexpectedly unable to produce power during significant portions of recent years. This unexpected downtime is known as a “forced outage” with the “forced outage rate” being the percent of hours in which a unit was in forced outage. The Schahfer units experienced the following forced outage rates over the past two

years, which were well above the national coal unit forced outage average rate of 12.0%.

Unit	Forced Outage Rate	
	2024	2025*
17	18.8%	15.9%
18	13.2%	78.2%

* through
September

Ex. 4 at 5 (citing NIPSCO public filings including Exs. 14–16 (Saffran Q1, Q2, Q3 2025 Outage Testimony)). Mr. Powers, drawing on his experience of over 40 years in the fields of power plant operations and environmental engineering, opined that these high outage rates “reflect[] the impact of worn and difficult-to-repair or replace coal unit components on operational reliability” and “point to degraded Schahfer 17 and 18 reliability [that] will degrade further if the units are required to run for extended periods of time, are required to stop and start numerous times, or attempt to start up at an accelerated rate in response to extreme demand conditions.” Ex. 4 at 1, 6–7 (Powers January Decl.). Mr. Powers noted that the jump in the forced outage rate in 2025 was “likely exacerbated” by underspending on operating and maintenance (“O&M”) and capital outlays as the Schahfer units reached their expected end of life. *Id.* at 8. He described how elements of the Schahfer units’ air emissions control system—including electrostatic precipitators, the wet limestone scrubber, and ultra-low NO_x burners—need regular maintenance to stave off degradation. *Id.* at 19. He further opined, “It cannot be assumed that the Schahfer 17 and 18 pollution control equipment is in good working order and will operate reliably to control the facility’s emissions beyond December 2025.” *Id.*

b. Schahfer Is Inflexible.

In addition to its reliability problems outlined above, the Schahfer plant also takes significant time to start up from a cold condition, as shown in the following table:

Unit 17	Unit 18
23 hours	23 hours

Ex. 4 at 10 (Powers January Decl.) (citing Ex. 19, NIPSCO CPCN Discovery Responses). These startup times are very long, even for coal units. *See* Ex. 118 at PDF p. 3 (RMI Analysis of Coal Plants’ Threats to Reliability) (stating that the

average coal plant takes 12 hours to reach max capacity from a cold start); Ex. 55 at 26 (IEA Flexibility Report) (similar). Even if Schahfer could provide power reliably—and it cannot—the units’ long start times mean the plant is ill-suited to provide peaking power during periods of high demand—precisely the periods the March Schahfer Order appears intended to address. A peak demand event may not become apparent to system operators at MISO until just a few hours before the actual peak. Ex. 4 at 10-11 (Powers January Declaration) (citing Ex. 85 (MISO Attributes Roadmap)). Moreover, bringing the Schahfer units from a cold start condition to full output to meet extreme demand would cost around \$300,000 each time. *Id.* at 11 (citing Ex. 54 at 16 (NARUC Coal Report)). The alternative to incurring those costs would be the costly approach of running the units on a “Must Run” or “Self-Scheduled” basis. *Id.*

c. Schahfer Is Dirty.

Schahfer has been a significant source of pollution. Each year when operating, the plant emitted hundreds of thousands of pounds of air toxics, hundreds of thousands of pounds of particulate matter (“PM”), many millions of pounds of nitrogen oxides and sulfur dioxide, and billions of pounds of carbon dioxide. *See* U.S. Env’tl. Prot. Agency (“EPA”), ECHO, <https://echo.epa.gov/air-pollutant-report?fid=110000493706> (last visited Jan. 6, 2026). In 2023, the plant discharged nearly 29 million pounds of pollution into nearby water bodies, including the Kankakee River, including 23,000 pounds of toxic metals. EPA, ECHO, <https://echo.epa.gov/detailed-facility-report?fid=110000493706> (last visited Jan. 6, 2026). PIOs’ expert engineer, Mr. Powers, calculated that if Schahfer 17 and 18 operated during the 90-day period of the December Schahfer Order with the same level of production they maintained in January-March 2025, more than 140,000 pounds of SO₂, 675,000 pounds of NO_x, 535,000 tons of CO₂, and 104,000 pounds of PM would be emitted. (As Mr. Powers notes, that analysis ignores that Unit 18 actually needs extensive repairs to become operable, as discussed *infra* in sec. V.B.2.) Ex. 4 at 14-15 (Powers January Decl.).

Emissions from Schahfer have serious health harms. EPA’s Co-Benefits Risk Assessment (“COBRA”) tool demonstrates that retiring Schahfer would reduce nationwide mortality by 9.4 to 16 deaths per year due to reductions in PM_{2.5}, SO₂,

and NO_x emissions. Ex. 154 at PDF p. 5 (EPA COBRA Schahfer Retirement Analysis).⁹

Additionally, burning coal at Schahfer creates toxic coal ash. The plant already holds roughly 1 million cubic yards of coal ash in an on-site impoundment. Ex. 88 at 2 (Schahfer Waste Disposal Area Closure Plan). Groundwater monitoring at Schahfer's Waste Disposal Area has consistently, over several years, shown statistically significant levels (above background concentrations) of lithium, molybdenum, and arsenic at downgradient groundwater monitoring wells. Ex. 147 at 5-7 (Schahfer 2024 Groundwater Monitoring Report). At Schahfer's Restricted Waste Site Type I landfill, the September 2025 groundwater monitoring event also showed statistically significant exceedances above background levels for lithium, molybdenum, and arsenic at downgradient monitoring wells. Ex. 184A at 6 (Schahfer Landfill 2025 Groundwater Monitoring Report, part 1).

d. Schahfer Is Expensive.

Schahfer costs significantly more money to run than it can earn in the market. If Units 17 and 18 run at their average capacity factor from 2020 through 2025 (and ignoring for purposes of analysis the fact that Unit 18 is broken), they are expected to lose \$9.8 million and \$8.9 million, respectively, during the 90-day term of the Order. Ex. 5 at 6 (Synapse Report).¹⁰

Schahfer has gotten even more expensive to run since 2021. In 2024, the cost of Schahfer's power rose to \$80.93 per MWh, a 66% increase over the 2021 cost. Ex. 49 at PDF p. 2 (2025 Energy Innovation Dataset). This means the cost of Schahfer's power grew significantly faster than inflation (roughly 16%) over the same period. Ex. 50 at 3 (2025 Energy Innovation Coal Cost Report); *see also* Ex. 51 at 12-13 (2023 Energy Innovation Coal Cost Report) (describing the same methodology used in the 2025 report).

⁹ PIOs obtained this analysis in the public COBRA portal by entering the annual Schahfer emissions of PM_{2.5}, SO_x, and NO_x, based on data from EPA's CAMPD database, as reductions from the Jasper County and Porter County (Indiana) "Fuel Combustion: Industrial" source.

¹⁰ The Synapse Report calculated revenues and costs on an annualized basis and then calculated three months' worth. *See* Exhibit 5 at *passim*.

ii. *Culley Unit 2 Exemplifies These Unwanted Attributes.*

a. *Culley 2 Is Old and Unreliable.*

Culley 2, at sixty years old, is at least ten years beyond the typical operational life of coal units. Ex. 4 at 9 (Powers January Declaration). CenterPoint Indiana has stated that Culley 2 has “run past its useful life” as the basis for its planned retirement in 2025. Ex. 80 at 30 (CenterPoint Indiana 2025 IRP Summary). In the table below, and with further context in his declaration, PIOs’ expert engineer Bill Powers identifies how Culley 2’s forced outage rate has steadily increased over the past half-decade, based on CenterPoint Indiana’s filings with the Indiana Commission.

Culley 2 Forced Outage Rate, 2020-2024					
Unit	2020	2021	2022	2023	2024
Culley 2	6.3%	21.9%	26.6%	24.8%	32.4%

Ex. 4 at 8 (Powers January Decl.) (citing Ex. 22, CenterPoint 2024 Performance Report). Mr. Powers states that this data “points to degraded Culley 2 reliability.” Ex. 4 at 8–9 (Powers January Decl.). Mr. Powers further highlighted CenterPoint’s public disclosure that its maintenance expenditure declined about 20% from 2022 to 2023 in account 512 (Maintenance of Boiler Plant). *Id.* at 9 (citing Ex. 152, CenterPoint Rate Case Discovery Responses). Mr. Powers noted that increased maintenance spending (missing recently at Culley 2) “is necessary to minimize the effect of equipment degradation with age and changing operating regimes.” *Id.* at 9.

b. *Culley 2 Is Inflexible.*

To gauge the startup time of Culley 2, it is instructive to consider the startup time for another coal generating plant formerly within CenterPoint Indiana’s portfolio. The A.B. Brown coal units required 18 to 24 hours for a cold start. Ex. 153 at 30 (Wayne Games 2018 Testimony). And Culley 2 is over a decade older than the two A.B. Brown units. *Id.* at 13. As noted above in section IV.C.3.i.b, the startup time of an average coal unit is 12 hours. A cold start time in this range renders Culley 2 unhelpful for responding in real time to emergency conditions. PIOs’ expert Mr. Powers opined that like Schahfer, “Culley 2 would not be able to meet a previously unanticipated exceptional MISO peak demand unless it was already online.” Ex. 4 at 12 (Powers January Decl.). A cold start of Culley 2 would also cost approximately \$37,000 each time; and the cost of running Culley 2 on “Must Run” or “Self Scheduled” commitment status to avoid cold starts solely to be prepared for a potential demand peak would be higher. *Id.* at 12.

c. *Culley 2 Is Dirty.*

Culley 2 has been a significant source of pollution. Each year when operating, the plant emitted tens of thousands of pounds of air toxics, hundreds of thousands of pounds of particulate matter, millions of pounds of nitrogen oxides and sulfur dioxide, and billions of pounds of carbon dioxide. See EPA, ECHO, <https://echo.epa.gov/air-pollutant-report?fid=110000403723> (last visited Jan. 11, 2026). In 2023, the plant discharged approximately 92.5 million pounds of pollution into the Ohio River, including nearly 2,000 pounds of toxic metals. EPA, ECHO, <https://echo.epa.gov/detailed-facility-report?fid=110000403723> (last visited Jan. 11, 2026). In 2024, under the National Emissions Standards for Hazardous Air Pollutants, EPA initiated an administrative penalty action against CenterPoint Indiana for alleged exceedance of Culley 2's 30-boiler-operating-day rolling average emissions limit for mercury. Allegedly, the exceedance began when Unit 3 experienced a catastrophic boiler feed pump turbine failure in June 2022 and remained out of service through mid-March 2023. CenterPoint Indiana agreed to a Consent Agreement and Final Order involving payment of an \$81,500 civil penalty. EPA, ECHO, Civil Enforcement Case Report (Docket No. CAA-05-2024-0031), https://echo.epa.gov/enforcement-case-report?activity_id=3603947405.

PIOs' expert engineer, Mr. Powers, calculated three months ago that if Culley 2 operated during the 90-day period of the December Culley Order with the same level of production it maintained in January–March 2025, more than 113,000 pounds of SO₂, 160,000 pounds of NO_x, 60,000 tons of CO₂, and 153,000 pounds of PM would be emitted. Ex. 4 at 16–17 (Powers January Decl.). The COBRA tool demonstrates that retiring Culley 2 would reduce nationwide mortality by 2.5 to 3.9 deaths per year due to reductions in PM_{2.5}, SO₂, and NO_x emissions. Ex. 155 at PDF p. 5 (EPA COBRA Culley Retirement Analysis).¹¹

Additionally, burning coal at Culley 2 creates toxic coal ash. The plant already holds roughly 350,000 cubic yards of coal ash in the on-site East Ash Pond, which receives bottom ash sluice water and FGD wastewater from Unit 2. Ex. 98 at 2-2 (Culley East Ash Pond Closure Plan); Ex. 109 at 4-1–4-2 (Culley East Ash Pond Extension Demonstration). Groundwater monitoring data around Culley's East Ash

¹¹ PIOs obtained this analysis in the public COBRA portal by entering the annual Culley 2 emissions of PM_{2.5}, SO_x, and NO_x, based on data from EPA's CAMPD database, as reductions from the Warrick County (Indiana) Fuel Combustion: Electric Utility source. Ex. 155 at 4 (Culley COBRA Analysis).

Pond show that releases of the toxic pollutant molybdenum exceed federally set safety levels. Ex. 148 at 2, 4, 7 (Culley 2024 Groundwater Monitoring Report).

d. Culley 2 Is Expensive.

Culley 2 costs significantly more money to run than it can earn in the market. CenterPoint Indiana Vice President of Power Supply Wayne Games testified in 2018 that “[s]ince 2008, the [A.B.] Brown plants and Culley Unit 2 cycle more than any other Vectren South [CenterPoint Indiana] plant because they are not competitive in the MISO energy market.” Ex. 153 at 14 (Wayne Games 2018 Testimony). He referred to Culley 2 (together with the A.B. Brown coal plant) as “among the most inefficient units within the State” and “the smallest and more expensive coal units in the MISO stack.” *Id.* at 7, 8.

Moreover, if the unit runs at its average capacity factor from 2020 through 2025, the unit is expected to cost \$1.8 million during the 90-day term of the December Culley Order. Ex. 5 at 6 (Synapse Report). Looking beyond the near term of the December Culley Order, Culley 2 would need extensive capital upgrades to run over a longer period. As CenterPoint Indiana’s executive, Mr. Games, stated in 2018 as the company first explained its retirement plan for Culley 2:

“[A] minimum of \$70 million in additional capital investments are required to continue operating Culley Unit 2 through 2036. In part, this investment is driven because Culley Unit cannot solely rely on Culley Unit 3 for environmental compliance costs. A dry bottom ash system must be installed to comply with CCR and further investments may be required to comply with section 316b of the Clean Water Act (designed to protect fish and other aquatic wildlife at water intake and outfall structures) on the design and operation of the current river intake structure. In addition to these environmental costs, Culley Unit 2’s distributed control system (‘DCS’) is a Honeywell system 1 installed in 2000 and must be updated or replaced because it is obsolete. A few other significant capital investments that would be required to keep Culley Unit 2 operating beyond 2023 include a turbine major overhaul, boiler acid clean, main transformer overhaul/replacement, major boiler component replacement, dry stack ductwork replacement, ID fan discharge ductwork, coal conveyor gallery replacement, boiler/high energy piping condition assessment, air heater basket replacement, continued overhaul of circulating water pumps and traveling water screens, and replacement of two 480-volt motor control center electrical switchgear.”

Ex. 153 at 20-21 (Wayne Games 2018 Testimony). The referenced ash handling system was later approved for construction in 2022, with a capital cost equaling a portion of \$19 million. Ex. 125 at 12 (IURC AB Brown CT Order). Additional information on required upgrades for continued operation of Culley 2, costing at least \$16 to \$20 million, is described *infra* at sec. IV.C.5.iii.

All of these harms could be avoided by retiring Culley 2 and Schahfer 17 and 18 as planned. As further discussed below, CenterPoint Indiana South and NIPSCO wanted to retire these Plants at the end of 2025. MISO approved the retirements, and the Indiana Commission approved utility actions contemplating both Schahfer and Culley 2 retirements.

4. Schahfer's Retirement Has Been Carefully Planned and Well Executed to Ensure Resource Adequacy.

NIPSCO has been diligently planning the retirement of Schahfer's coal units since at least 2018. In Indiana, IRPs are rigorous processes that involve sophisticated modeling and scrutiny by diverse stakeholders and regulators. *See* section IV.A.4, above. In its 2018 IRP, NIPSCO announced a preferred resource plan that included the retirement of all four Schahfer coal units by 2023. NIPSCO's short term action plan from the 2018 IRP focused on initiating the retirement process for all four of the Schahfer coal units and acquiring replacement resources to fill the energy and capacity gap resulting from the retirements. NIPSCO's 2018 IRP determined that the retirement of Schahfer coal units provided "significant cost savings versus the status quo and offer[ed] an acceptable outcome for portfolio flexibility and with regard to the impact on employees and the local economy." Ex. 71 at 156 (NIPSCO 2018 IRP).

In its 2021 IRP, published in November of that year, NIPSCO noted that Schahfer Units 14 and 15—the larger coal generating units at the site—had been retired earlier that year, and NIPSCO stated that "Units 17 and 18 are on track to retire by the end of 2023." Ex. 72A at 9 (NIPSCO 2021 IRP, part 1). NIPSCO again confirmed that retiring these coal units was economically advantageous. In the 2021 IRP, NIPSCO noted that it continued to make progress on over a dozen Indiana Commission-approved generation projects to replace the retired capacity at Schahfer. Ex. 72A at 9 (NIPSCO 2021 IRP, part 1).

In May 2022, NIPSCO announced plans to delay the retirement of Schahfer Units 17 and 18 until 2025 after several solar projects faced delays associated with a United States Department of Commerce anti-dumping investigation. Ex. 73 (NIPSCO May 2022 Investor Call).

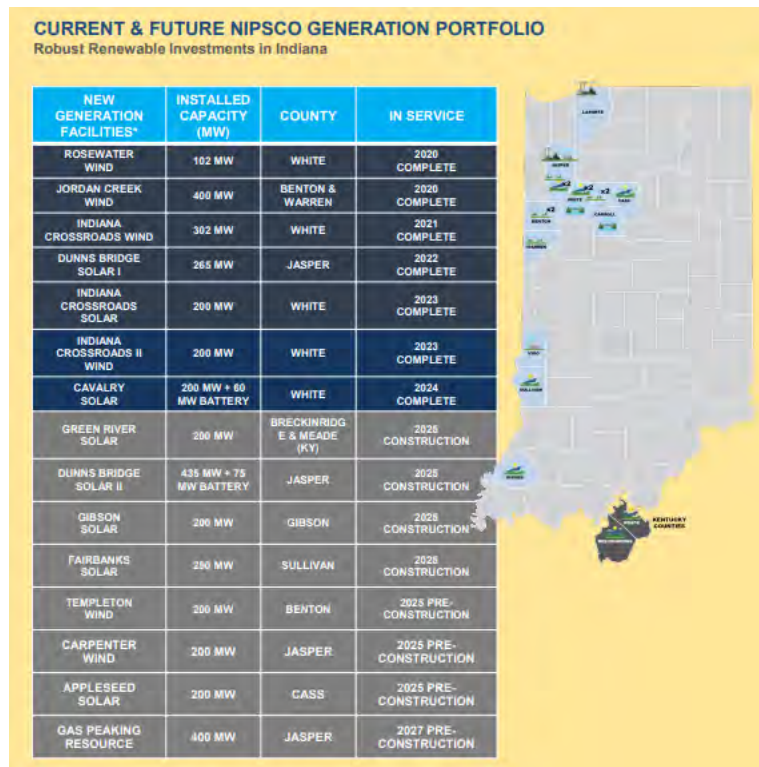
NIPSCO's 2024 IRP confirmed that Schahfer Units 17 and 18 "remain on track to retire by the end of 2025." Ex. 100A at 6 (NIPSCO 2024 IRP, part 1). To replace the retiring capacity at Schahfer, NIPSCO noted that it continued to make progress on its fourteen Indiana Commission-approved renewable energy projects, including wind, solar, and solar plus battery storage resources, while also gaining regulatory approval for a natural gas peaking resource that will be located at the Schahfer property and use the interconnection rights associated with the retiring Units 17 and 18. Ex. 100A at 1, 6–7 (NIPSCO 2024 IRP, part 1); Ex. 20 at 10, 17, 41 (IURC Schahfer Gas Plant Order); Ex. 132 at PDF pp. 14–16 (NIPSCO Rate Case Discovery Responses).

In sum, the retirement of Schahfer Units 17 and 18 results from nearly a decade of planning. In each of these successive resource planning exercises, NIPSCO confirmed that its customers would benefit from the retirement of Schahfer coal units.

i. Schahfer's Retirement Was the Product of a Generation Replacement Strategy that Improves Resource Adequacy.

Over the last decade, NIPSCO has brought forward and the Indiana Commission has approved a suite of generation resources that replace the output of the Schahfer coal units. As NIPSCO is moving from reliance on large single-station generation to a fleet of modern, smaller, more nimble generating units, the replacement of Schahfer is expected to improve reliability and grid resilience. *See* Ex. 132 (NIPSCO Rate Case Discovery Responses).

Figure 5: excerpt from Ex. 100A at Summary p. 7 (NIPSCO 2024 IRP, part 1).



In Cause No. 45947, the Indiana Commission approved ~400 MW of gas peaking capacity to be located at the Schahfer site. Ex. 20 (IURC Schahfer Gas Plant Order). NIPSCO relied on its planned retirement of Schahfer to demonstrate that the gas plant was displacing coal and eligible for construction-work-in-progress financing incentives under Indiana law. *Id.* at 21 (“Partial displacement of retiring coal-fired energy generation with a gas peaking resource has been a component of NIPSCO’s IRP modeling and related CPCN regulatory filings since 2021. As such, we find the CT Project is being constructed to displace energy from an existing coal-fired generation facility and is therefore eligible for [construction-work-in-progress financing].”). The IDEM-issued air permit for these new peaking units provides that NIPSCO must retire Schahfer Units 17 and 18 before the combustion turbines begin to operate. Ex. 101 at 34 (Schahfer Title V Permit Modification) (“Upon the commencement of operation of the natural gas-fired simple cycle combustion turbines, identified as 19A, 19B, 19C, and Unit 20, the two (2) dry bottom pulverized coal-fired boilers, identified as Unit 17 and Unit 18, shall be permanently shutdown and subsequently decommissioned from the source.”). Moreover, as noted above in this section IV.C.4, the new gas peaking capacity relies on using the retiring coal-fired units’ existing transmission system interconnection rights.

Collectively, these projects improve reliability. These projects will allow NIPSCO to continue to meet its resource adequacy requirements. *See* section IV.A.4. The battery and peaking gas units are capable of responding to disturbance on the grid and to changing generation needs much more quickly than the coal units. Ex. 132 (NIPSCO Rate Case Discovery Responses).

ii. MISO and the Indiana Commission Continue to Take Actions in Reliance on Schahfer's Retirement.

For MISO asset owners like NIPSCO, no generating unit is permitted to retire without first being approved by MISO for retirement through a process that assures transmission system stability and resource adequacy. In January 2023, NIPSCO requested that MISO approve a retirement date of December 31, 2025, for Schahfer Units 17 and 18. In February 2023, MISO approved the retirement of Schahfer Units 17 and 18, finding no impact on reliability:

“After being reviewed for power system reliability impacts as provided for under Section 38.2.7 of MISO’s Open Access Transmission, Energy, and Operating Reserve Markets Tariff (“Tariff”), the suspension of Schahfer Units 17 and 18 would not result in violations of applicable reliability criteria. Therefore, Schahfer Units 17 and 18 may suspend without the need for the generators to be designated as System Support Resource (“SSR”) units as defined in the Tariff.”

Ex. 102 at PDF p. 12 (MISO Attachment Y Response to NIPSCO).

The Indiana Commission has also endorsed the retirement of Schahfer Units 17 and 18 in two distinct regulatory processes.

First, in 2019, 2023, and 2025 electric rate case final orders, the Indiana Commission approved depreciation rates and operations and maintenance spending for Schahfer that assumed NIPSCO’s expected retirement dates. *See* Ex. 103 at 120 (NIPSCO 2019 Rate Order) (summarizing approved depreciation adjustment and noting NIPSCO’s associated plan to retire Schahfer coal units); Ex. 104 at 13-14 (NIPSCO 2023 Rate Order) (approving demolition costs for Schahfer and adjusting depreciation recovery for Schahfer units); Ex. 106 at 23 (NIPSCO 2025 Rate Order) (describing approved settlement’s reduction of O&M spending in revenue requirement for Schahfer Units 17 and 18 with their expected retirement in December 2025). While depreciation timelines and adjustments to O&M spending included in base rates do not legally require that a retirement occur on the projected retirement date, in each of these cases a broad coalition of stakeholders, including the Indiana Office of Utility Consumer Counselor (the statutory ratepayer representative), entered into a settlement agreement with NIPSCO that assumed

the units would retire as projected by the utility, and agreed to adjust depreciation schedules and O&M spending accordingly. In each of these cases, the Indiana Commission approved the Schahfer depreciation schedule or O&M spending, while noting the utility's intention to retire the units.

Second, the Indiana Commission approved Certificates of Public Convenience and Necessity ("CPCNs") that NIPSCO received for new generation resources from 2018 through 2025, that were justified, in part, on a stated need to replace the Schahfer coal units. In approving these projects, the Indiana Commission explicitly noted that the generation was intended to replace Schahfer. The Indiana Commission order approving the 400 MW of gas peaking capacity for the Schahfer site, for example, found that "[Combustion Turbine] Project is designed to reliably cycle in response to the MISO market and will displace the retiring Schahfer coal units with more efficient and controllable load-following capacity." Ex. 20 at 28 (IURC Schahfer Gas Plant Order). Other CPCN orders approving NIPSCO's replacement generation include Indiana Commission Cause Nos. 45818, 45936, 45500, 46028, 45908, and 45887. In other words, the Commission has relied on and not objected to the plan for Schahfer retirements as it has approved NIPSCO's requests to build and charge customers for the cost of projects explicitly designed to replace the Schahfer units.

5. Culley 2's Retirement Has Been Carefully Planned and Well Executed, and Overseen by the Indiana Commission to Ensure Resource Adequacy.

CenterPoint Indiana has been planning the retirement of Culley 2—its "oldest, smallest (83 MW), and most inefficient coal generating unit"—for over a decade. Ex. 107 at 33 (Vectren 2014 IRP). In its 2014 IRP, CenterPoint Indiana found that retiring Culley 2 in 2020 would save customers money, but deferred making a decision due to load-growth and regulatory uncertainty. *Id.* at 25-26. The 2016 IRP confirmed that retiring Culley 2 in 2024 was part of the preferred plan for serving its customers. Ex. 108 at 44 (Vectren 2016 IRP). CenterPoint Indiana official Wayne Games informed the Indiana Commission two years later that:

"Investing so heavily in a unit as old and inefficient as Culley Unit 2 is not economic. Vectren South's modeling bore this out. Due to the higher cost to operate, the unit has experienced less overall run time and much more unit cycling. Culley Unit 2 has reached the end of its useful life and should be retired rather than continuing to spend capital keeping the inefficient unit operating."

Ex. 153 at 21 (Wayne Games 2018 Testimony).

i. Culley 2's Retirement Was the Product of a Generation Replacement Strategy that Improves Resource Adequacy.

CenterPoint Indiana's initial plan to replace Culley 2 and the A.B. Brown coal plant with a combined-cycle gas facility at the A.B. Brown site was rejected by the Indiana Commission in 2019. *See* Ex. 114 (IURC 2019 CCGT Order). The Indiana Commission rejected this replacement gas facility because it found that the utility had failed to adequately consider alternatives, including the ability of renewables to replace some of the retiring coal energy and capacity. *Id.* at 25–28. The Indiana Commission directed CenterPoint Indiana to reevaluate its plan to replace its retiring coal units.

In its 2020 IRP, CenterPoint Indiana announced its revised coal-replacement preferred plan, responding to the Indiana Commission's order in Cause No. 45052. Instead of replacement with a single combined cycle gas facility, the revised plan called for replacement of the majority of CenterPoint Indiana's coal fleet—including A.B. Brown and Culley 2—by the end of 2023 with 700-1,000 MWs of solar, 300 MWs of wind, energy efficiency, and two gas combustion turbines ("CTs") totaling 460 MW. Ex. 115 at 51 (Vectren 2020 IRP). CenterPoint Indiana found that the fast-ramping CTs, combined with the wind and solar resources, enabled the utility "to maintain constant electric supply during potentially extended periods of low output" from renewables. *Id.* at 34–35. CenterPoint Indiana found that the 2020 preferred plan would save its customers \$320 million over the study period compared to continued operation of its existing coal generation. *Id.* at 35.

In its 2023 IRP, CenterPoint Indiana observed that the Indiana Commission's approval of five generation projects from its 2020 preferred plan "affirms the direction taken" in replacing its coal units. Ex. 116 at 36 (CenterPoint 2023 IRP). The 2023 IRP modeling again found that a preferred portfolio that included the retirement of Culley 2 in 2025 would save its customers money. *Id.* at 38, 56; *see also id.* at 57 (preferred portfolio "[s]aves customers nearly \$80 million over the next 20 years when compared to continued operation of F.B. Culley with coal."). CenterPoint's 2025 IRP again found that retiring Culley 2 in 2025 was a part of the utility's preferred plan. Ex. 80 at 20 (CenterPoint Indiana 2025 IRP Summary).

ii. MISO Likely Approved Culley 2's Retirement, and the Indiana Commission has Approved Adjustments to the Culley Depreciation Schedule and Repeatedly Approved Generation Projects Specifically Designed to Allow Culley 2 to Retire.

CenterPoint Indiana submitted an Attachment Y notice to MISO, as required under MISO's FERC-approved tariff, seeking approval to retire Culley 2 at the end of 2025. Ex. 21 at 52 (CenterPoint Indiana 2025 IRP). While the MISO response to

this Attachment Y filing has not been made public, CenterPoint noted that Culley 2 had operated “past its useful life” and remained on track for a 2025 retirement. *Id.* at 30. CenterPoint noted in a recent filing at FERC that “MISO reviewed the Company’s suspension request for Culley Unit 2 and found no reliability criteria violations.” Ex. 128 at 9 (CenterPoint Cost Allocation Complaint).

The Indiana Commission has supervised CenterPoint’s resource planning and endorsed the retirement of Culley 2 in two categories of regulatory proceedings. Since 2020, the Indiana Commission has approved a series of generating resources that were explicitly premised on replacing Culley 2 and other now-retired coal units. For example, in Cause No. 45564, in approving the construction of 460 MW of gas peaking capacity, the Indiana Commission observed that the “Preferred Portfolio identified through the 2019/2020 IRP called for the retirement or exit of energy provided by coal-burning units at the Brown and Culley generating stations.” Ex. 125 at 16 (IURC AB Brown CT Order). The Indiana Commission further observed of this replacement plan:

“The Preferred Portfolio mapped a shift from a generating fleet of predominantly coal-burning resources to one of intermittent renewable resources supported by gas generation to ensure reliability. One early step in implementing the Preferred Portfolio was the addition of solar generating resources approved by the Commission in Cause Nos. 45501 on October 27, 2021 and 45600 on May 4, 2022. A next step is the addition of the two new CTs requested in this Cause.”

Id. at 16. Thus, in approving CPCNs for replacement resources, the “steps” in CenterPoint Indiana’s replacement plan, the Indiana Commission approved CenterPoint Indiana’s plan to retire and replace Culley 2.

Second, in Cause No. 45990, a CenterPoint Indiana electric rate case, the Indiana Commission approved an adjustment in test-year spending associated with the retirement of Culley 2. Ex. 126 at 58 (IURC 2025 CenterPoint Rate Order); *see also* Ex. 127 at 30 (Chrissy Behme Testimony) (rate schedules filing “reflects a pro forma adjustment decrease to test year expense associated with F.B. Culley Unit 2, which is forecasted to retire at the end of the test year.”). In other words, the Indiana Commission has already approved a reduction in rate recovery associated with the Culley 2 retirement.

iii. CenterPoint Indiana Asked the Department to Not Renew the December Culley Order.

In February of this year, CenterPoint Indiana furnished a letter to the Department, noting that “maintaining F.B. Culley Unit 2 [] will require substantial

investment to support an inefficient and increasingly unreliable asset, rather than advancing affordable and reliable service for customers in southwestern Indiana.” Ex. 169 at 1 (CenterPoint Letter to USDOE). CenterPoint specifically asked the Department to “allow [the December Culley Order] to expire on March 23, 2026, and abstain from issuing subsequent Section 202(c) directives for Unit 2.” *Id.* CenterPoint indicated that it “ha[s] adequate generation capacity – without Unit 2 – to meet MISO’s Planning Reserve Margin Requirement through the 2027–2028 Planning Year[.]” *Id.* For the 48 days from the date of the December Culley Order through February 8, 2026, Unit 2 was on outage due to equipment issues for 26 days; available but not economically dispatched on five days; and on 17 other days, running but limited to between 45 MW and 78 MW (net) due to maintenance issues. *Id.* at 2.

What’s more, as CenterPoint stated, reviving Culley 2 to a shipshape condition would be extremely lengthy and expensive. “Safe and reliable operation beyond March 2026 hinges on major and costly interventions, including acid cleaning of the boiler and replacement of boiler tubes—necessitating a four-week or longer outage, with projected cost of approximately \$1.9 million – \$2.5 million.” *Id.* at 2. CenterPoint also indicated that Culley needs an “unavoidable” turbine overhaul (as current operation is significantly increasing the risk of catastrophic mechanical failure”), which would entail a 10-week outage and total expenditures of at least \$14 million – \$18 million, if not more. *Id.* at 2. CenterPoint stated that “extending the life of Unit 2 is neither practical nor financially responsible.” *Id.* at 2.

V. REQUEST FOR REHEARING

The Orders are a manifestation of the Department’s overarching policy to systematically misapply Section 202(c) of the Federal Power Act to preserve fossil-fueled power plants, including coal-fired plants, that otherwise would be retired. That policy aims to bolster the fossil energy industry, irrespective of need, expense, and harm. In its zeal to implement its policy through issuance of the Orders, (1) the Department has exceeded the authority Congress gave it, using its “emergency” powers in the absence of any imminent shortfall to impose federal control over basic generation and supply decisions; and (2) the Department has done so without reasoned decision-making and on the basis of purported “facts” that are not supported by credible evidence. *See Michigan v. EPA*, 268 F.3d 1075, 1081 (D.C. Cir. 2001) (explaining that, absent statutory authorization, an agency’s action is contrary to law); *Allentown Mack Sales & Serv., Inc. v. Nat’l Labor Rel. Bd.*, 522 U.S. 359, 374 (1998) (explaining agency obligation to undertake reasoned-decision-making); *Motor Vehicle Mfrs. Assn. of United States, Inc. v. State Farm Mut. Automobile Ins. Co.*, 463 U.S. 29, 43 (1983) (same); *Burlington Truck Lines, Inc. v.*

United States, 371 U.S. 156, 168 (1962) (“The agency must make findings that support its decision, and those findings must be supported by substantial evidence.”); *Butte Cnty. v. Hogen*, 613 F.3d 190, 194 (D.C. Cir. 2010) (“[A]n agency cannot ignore evidence contradicting its position.”). Numerous examples of the Department’s unreasoned and unlawful decision-making are described throughout this section V. The only plausible explanation for these repeated legal errors is that the Department has prioritized implementing its policy over compliance with law.

Congress never conferred on the Department the broad authority over the country’s mix of power generation resources that the Department seeks to wield under the pretense of responding to claimed “emergencies.” To the contrary, Congress explicitly reserved authority over resource adequacy and grid reliability to the states, FERC, and NERC. *See, e.g.*, 16 U.S.C. §§ 824(a)–(b), 824o; *Pac. Gas & Elec.*, 461 U. S. at 205. Both the agency’s new policy and the Orders exceed the Department’s authority and are therefore contrary to law.

Before tackling the Orders’ legal faults and issues, *see infra* sections V.A through V.D, it is useful to understand the broader context of the Department’s policy. The Department acknowledges that its Orders are based on a government-wide policy—dictated by Executive Order—of promoting fossil-based energy through the use of any emergency powers executive departments and agencies could try to invoke. The Orders rely upon the Energy Emergency EO, 90 Fed. Reg. 8433, which directs the heads of all executive departments and agencies to use “emergency authorities” and “other lawful authorities” to facilitate the production, extraction, creation, and generation of coal and other fossil fuels.

The Orders also rely on another executive order, the Grid EO (Ex. 93). The Grid EO was issued at the same time as three other executive actions aimed at giving a lifeline to the coal industry, and was announced at a White House political event focused on promoting coal. Ex. 94 (NY Times Coal Article). In essence, the Grid EO calls on the Department to assume the authority for resource adequacy and grid reliability decision-making that the Federal Power Act reserves to others, and to “systemize” the issuance of Section 202(c) orders for that improper purpose. *See* Ex. 93, 90 Fed. Reg. at [15521](#)–22 (Grid EO) (directing the Department to “streamline, systemize and expedite” the issuance of Section 202(c) orders; to develop a “uniform methodology” for assessing reserve margins and a protocol to retain generators the Secretary deems critical to system reliability; and to prevent certain generators from leaving the bulk-power system or converting to a different fuel source).

The Department’s words and actions following issuance of the Grid EO reveal its efforts to unlawfully arrogate to itself others’ lawful authority through systematic

misapplication of Section 202(c) to prop up coal-burning power plants. The Department's initial steps included issuing a Section 202(c) order to prevent the well-planned retirement of the J.H. Campbell Generating Plant in Michigan. *See* Ex. 150 (May Campbell Order). The Department's order was clear on one point—Campbell cannot be allowed to retire—but left vague and unclear almost everything else. *See, e.g., Consumers Energy Co. v. Midcontinent Indep. Sys. Op., Inc.*, 192 FERC ¶ 61,158, at PP 39–40 (2025) (recognizing the variety of interpretations of the Campbell order and settling on “the most reasonable reading of the DOE Order's intended scope”). The May Campbell Order failed to make clear even where the grid supposedly needed energy from Campbell, selectively quoted sources without examining their context and core findings, and flouted Congress' explicit limitations on the Department's Section 202(c) powers. *See* Motion to Intervene and Request for Rehearing and Stay of Sierra Club et al. at *passim* (June 18, 2025), <https://www.energy.gov/sites/default/files/2025-07/PIO%20Request%20for%20Rehearing%20of%20Order%20No.%20202-25-3.pdf>.

After preventing Campbell's retirement, the Department continued to implement its policy. In addition to the Orders on the NIPSCO and CenterPoint Indiana Plants, the Department has issued Section 202(c) orders to prevent fossil-burning plant retirements in Pennsylvania, Order Nos. 202-25-4, 202-25-8, & 202-25-10, in Washington, Order No. 202-25-11, and in Colorado, Order No. 202-25-14.

Additionally, on July 7, 2025, the Department published the “methodology” required by the Grid EO, which the Department explained will “guide reliability interventions,” including the use of Section 202(c) orders. Ex. 96 at vi (July 2025 Resource Adequacy Report); *see also* Ex. 97 at 3–4 (DOE July 7, 2025 Press Release) (“The methodology also informs the potential use of DOE's emergency authority under Section 202(c) of the Federal Power Act.”). The report identifies no present or imminent emergency; at most, using deeply flawed methodology, it identifies a theoretical shortfall of generation in 2030. As the Supreme Court has observed in rejecting the Trump Administration's emergency import tariffs, “‘Emergency powers,’ after all, ‘tend to kindle emergencies.’” *Learning Resources, Inc. v. Trump*, 607 U. S. ____ (2026), Slip Op. *12 (quoting *Youngstown Sheet & Tube Co. v. Sawyer*, 343 U. S. 579, 650 (1952)). Here, the asserted “emergency” by the Department is likewise merely an outgrowth of the Administration's policy preferences.

Taken together, the Energy Emergency EO, Grid EO, July 2025 Resource Adequacy Report, and the Department's Section 202(c) orders reflect a policy to promote the long-term preservation of fossil-fueled electric generation, including coal-fired generation, by using the Department's emergency authority under Section 202(c). To the extent these actions left any room for doubt that the Department has

such a policy, Energy Secretary Wright’s own words have removed it. In his statement to the press when the Centralia Order issued, Secretary Wright emphasized, “The Trump administration will continue taking action to keep America’s coal plants running.” Ex. 133 (Department Press Release on Centralia Order); *see also* Ex. 149 at *passim* (New York Times Article on Trump’s Coal Plant Policy); Ex. 76 (Secretary Wright’s West Virginia Remarks) (reporting Secretary Wright’s stated intention to stop the closure of coal plants and claiming authority to do so).

The Department has further reinforced this policy by applying it in the Orders.

A. *The Orders Address Circumstances Beyond the Lawful Scope of an Emergency Under Section 202(c), and Fail to Provide Evidence or Reasoned Decision-Making Substantiating the Existence of an Emergency that Can Come Within Section 202(c).*

1. *Legal Framework: Section 202(c) Empowers the Department to Respond Only to Imminent, Certain, and Unexpected Shortfalls in Electricity Supply.*

The Orders invoke Section 202(c) of the Federal Power Act, which provides:

“During the continuance of any war in which the United States is engaged, or whenever the Commission determines that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation of transmission of electric energy . . . the Commission shall have authority . . . with or without notice, hearing, or report, to require by order such temporary connections of facilities and such generation, deliver, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest.”

16 U.S.C. § 824a(c)(1). That authority was transferred to the Department by the Department of Energy Organization Act. *See* 42 U.S.C. § 7151(b).

Section 202(c)’s text and context establish that an “emergency” enabling the Department to over-ride state and private decision-making must be an event that is imminent, certain, and unexpected. 16 U.S.C. § 824a(c). The constrained scope of Section 202(c)’s emergency authority is confirmed by the broader statutory context—in particular, the separate regime delineating federal authority over bulk-system reliability in Section 215 of the Federal Power Act, *id.* § 824o—as well the Department’s regulations, caselaw applying Section 202(c), and the Department’s consistent past practice.

i. The Text and Context of Section 202(c) Confine an Emergency to Imminent, Certain, and Unexpected Events.

Section 202(c)'s text empowers the Department to require generation only in an "emergency." *Id.* § 824a(c). Both the ordinary meaning of the term (which the statute does not expressly define) and statutory context limit the Department's emergency authority to imminent, unexpected, and certain events. At the time Congress enacted Section 202(c), Webster's New International Dictionary of the English Language (1930) defined "emergency" as, with emphasis added here, a "*sudden or unexpected appearance or occurrence... An unforeseen occurrence or combination of circumstances which calls for immediate action or remedy; pressing necessity; exigency.*" Contemporary dictionaries similarly define "emergency" as demanding imminence: an emergency is "an *unforeseen* combination of circumstances or the resulting state that calls for *immediate* action." Merriam Webster's Dictionary 407 (11th ed. 2009) (emphasis added); *see* 3 Oxford English Dictionary 119 (1st ed. 1913) (defining emergency similarly as "a state of things *unexpectedly* arising, and urgently demanding *immediate* action" (emphasis added)); *see also* Benjamin Rolsma, *The New Reliability Override*, 57 Conn. L. Rev. 789, 812 n.147 (2025) (noting that dictionaries have given the term "emergency" the "same meaning for many years").

The remainder of Section 202(c) underscores the exigency inherent in the governing term "emergency." The authority granted by Section 202(c) is, in the first instance, a war-time power. 16 U.S.C. § 824a(c) (beginning with "[d]uring the continuance of any war in which the United States is engaged"); *see Jarecki v. G.D. Searle & Co.*, 367 U.S. 303, 307 (1961) (noting that statutory terms should be interpreted in the context of nearby parallel terms "in order to avoid the giving of unintended breadth to the Acts of Congress"). An "emergency" under the statute is limited to circumstances of similar urgency: "a *sudden* increase in the demand for electric energy," for example. 16 U.S.C. § 824a(c) (emphasis added); *see Richmond Power & Light v. FERC*, 574 F.2d 610, 615 (D.C. Cir. 1978) (holding that Section 202(c) "speaks of 'temporary' emergencies, epitomized by wartime disturbances"); S. Rep. No. 74-621, at 49 (1935) (explaining that Section 202(c) provides "temporary power designed to avoid a repetition of the conditions during the last war, when a serious power shortage arose").

The text's use of the present tense accentuates its focus on imminent and certain shortfalls: It empowers the Department to act only where "an emergency *exists*." 16 U.S.C. § 824a(c) (emphasis added). The Section's title and text both emphasize that it provides a "temporary" authority, further demonstrating that its scope extends only to immediate—not distant—needs. *Id.* § 824a(c), (c)(1); *see Dubin v. United States*, 599 U.S. 110, 120–21 (2023) (cleaned up) ("The title of a statute and the

heading of a section are tools available” to resolve “the meaning of a statute,” and “a title is especially valuable where it reinforces what the text’s nouns and verbs independently suggest.”). That near-term focus precludes use of Section 202(c) to pursue broader or long-term energy-policy goals, such as a “fear of overdependence” on foreign oil supplies, *Richmond Power & Light*, 574 F.2d at 617, or “energy independence,” Ex. 96 at 1 (July 2025 Resource Adequacy Report); *see also Richmond Power & Light*, 574 F.2d at 614 (Section 202(c) “speaks of ‘temporary’ emergencies, epitomized by wartime disturbances, and is aimed at situations in which demand for electricity exceeds supply and not those in which supply is adequate but a means of fueling its production is in disfavor.”).

Section 202’s overall structure further highlights Section 202(c)’s emphasis on imminent, near-term concerns. The preceding subsections in Section 202 (*i.e.*, 202(a) and (b)) together define and limit the tools by which the federal government may pursue “abundant” energy supplies in the normal course. 16 U.S.C. § 824a(a) (seeking “abundant supply of electric energy” by directing the federal government to “divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy”); *id.* § 824a(b) (allowing federal government to order “physical connection . . . to sell energy to or exchange energy” upon application, and after an opportunity for hearing). The resulting statutory “machinery for the promotion of the coordination of electric facilities” comprises the following: in subsection (a), an instruction to establish a general framework meant to facilitate “coordination by voluntary action;” in subsection (b), “limited authority to compel interstate utilities to connect their lines and sell or exchange energy,” subject to defined procedural and substantive requirements, when “interconnection cannot be secured by voluntary action;” and in subsection (c), “much broader” but “temporary” authority “to compel the connection of facilities and the generation, delivery, or interchange of energy during times of war or other emergency.” S. Rep. No. 74-651 at 49 (1935).

That tiered structure—placing primary emphasis on voluntary resource adequacy planning, 16 U.S.C. § 824a(a), specifying limited authority where that voluntary system fails, *id.* § 824a(b), and allowing for “temporary” central command-and-control only in case of an “emergency,” *id.* § 824a(c)—requires that Section 202(c) remain narrowly confined to instances of an immediate and unavoidable “break-down in electric supply,” S. Rep. No. 74-651 at 49 (1935), rather than a mere desire for more abundant supply in the future, *cf.* Ex. 1 at 4 (December Schahfer Order); Ex. 2 at 5 (December Culley Order); Ex. 158 at 8 (March Schahfer Order); Ex. 159 at 8 (March Culley Order) (emphasis added) (pointing to conditions that “will continue in the near term” and “are also *likely* to continue in *subsequent years*” that “*could* lead to the loss of power . . . in the areas that *may* be affected by curtailments or power outages, presenting a *risk* to public health and safety”). The

tiered structure authorizes increasingly intrusive federal intervention, but under increasingly narrow circumstances. Interpreting Section 202(c)’s “emergency” powers to permit the Department to compel generation based on nothing more than the generalized challenges of operating a reliable bulk electric system in a transforming energy landscape, or concerns over longer term resource adequacy, *see* Ex. 1 at 2 (December Schahfer Order), Ex. 2 at 1, 2 (December Culley Order) Ex. 158 at 1, 2 (March Schahfer Order); and Ex. 159 at 1, 2 (March Culley Order), would unwind the careful balance of voluntary, market-driven action and federal power set out in Sections 202(a) and 202(b). Such an interpretation cannot be squared with the statutory text and structure. *See Otter Tail Power Co. v. Fed. Power Comm’n*, 429 F.2d 232, 233–34 (8th Cir. 1970) (holding that Section 202(c) “enables the Commission to react to a war or national disaster,” while Section 202(b) “applies to a crisis which is likely to develop in the foreseeable future”).

ii. Congress’ Enactment of a Specific, Cabined Scheme to Address Reliability Concerns Confirms That Generalized or Long-Term Bulk-Power System Reliability Concerns Are Not an “Emergency” Under Section 202(c).

That the Department’s Section 202(c) emergency powers do not extend to general supervision of bulk-power-system reliability is confirmed by Section 215 of the Federal Power Act—which specifically and directly delineates the scope of federal authority to enforce mandatory reliability requirements for the bulk-power system. 16 U.S.C. § 824o. Congress added Section 215 to the Federal Power Act in 2005 precisely because the Act as it then existed—including Section 202—did not give the federal government the power to enforce measures designed to ensure bulk-system reliability. *See Rules Concerning Certification of the Elec. Reliab. Org.; and Procedures for the Establishment, Approval, and Enforcement of Elec. Reliab. Standards*, 70 Fed. Reg. 53117, 53118 (Sept. 7, 2005) (“In 2001, President Bush proposed making electric Reliability Standards mandatory and enforceable,” leading to enactment of Section 215 in 2005); Ex. 139 at 7-6 (*Report of the Nat’l Energy Pol’y Dev. Grp.*) (noting that “[r]egional shortages of generating capacity and transmission constraints combine to reduce the overall reliability of electric supply in the country” and that “one factor limiting reliability is the lack of enforceable reliability standards” because “the reliability of the U.S. transmission grid has depended entirely on *voluntary* compliance,” and then recommending “legislation providing for enforcement” of reliability standards (emphasis added)); S. Rep. No. 109-78 at 48 (2005) (stating that Section 215 “changes our current voluntary rules system” for bulk-system reliability “to a mandatory rules system”); *see also Alcoa, Inc. v. FERC*, 564 F.3d 1342, 1344 (D.C. Cir. 2009) (noting that prior to the Energy Policy Act of 2005, “the reliability of the nation’s bulk-power system depended on participants’ voluntary compliance with industry standards”).

By enacting Section 215, Congress provided a comprehensive and carefully circumscribed scheme to empower the federal government to enforce bulk-system reliability requirements. That statutory scheme strikes a careful balance between state and federal authority, and between private, market-driven decisions and top-down control. Reliability standards are devised by NERC independent “of the users and owners and operators of the bulk-power system” but with “fair stakeholder representation.” 16 U.S.C. § 824o(c)–(d); *see also id.* § 824o(a)(3) (defining reliability standards as “a requirement . . . to provide for reliable operation of the bulk-power system”). FERC may approve or remand those standards (but not replace them with its own) and is required to “give due weight” to NERC’s “technical expertise” while independently assessing effects on “competition.” *Id.* § 824o(d)(2)–(4). Section 215 provides specified enforcement mechanisms and procedures for reliability standards—which mechanisms conspicuously exclude the power to command specific generation resources to remain operational. *Id.* § 824o(e). And Section 215 carefully preserves state authority over “the construction of additional generation” and in-state resource adequacy, establishing regional advisory boards to ensure appropriate state input on the administration of reliability standards. *Id.* § 824o(i)–(j).

Interpreting Section 202(c) to permit the Department to mandate generation based on its own unfettered assessment of bulk-system reliability needs would effectively allow the Department to bypass Section 215’s procedural safeguards, constraints on federal authority, and protection of state power. Such a bypass would impermissibly “contradict Congress’ clear intent as expressed in its more recent,” reliability-specific legislation, enacted “with the clear understanding” that the Department had “no authority” to address long-term reliability through Section 202(c). *See FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 142 & 149 (2000); *see also Cal. Indep. Sys. Operator Corp. v. FERC*, 372 F.3d 395, 401–02 (D.C. Cir. 2004) (“Congress’s specific and limited enumeration of [agency] power” over a particular matter in one Section of the Federal Power Act “is strong evidence that [a separate Section] confers no such authority on [agency].”). Congress has, in Section 215, directly established the mechanisms (and limitations) by which the federal government may compel action to ensure the reliability of bulk-power electric system. In so doing, it has confirmed that the Department may not, through Section 202(c) “emergency” orders, use those reliability concerns to mandate the generation it views as required to address broad resource adequacy problems ; the Department’s emergency authority is confined to specific and imminent supply shortfalls requiring immediate response.

iii. The Department's Regulations Similarly Establish that Section 202(c) Emergency Authority Can Only Be Invoked to Address Imminent, Certain Supply Shortfalls Requiring Immediate Response.

The Department's regulations demonstrate its own long-standing understanding that Section 202(c)'s emergency authority is confined to imminent, certain, and otherwise unavoidable resource shortages, and does not provide a mechanism to address broad, long-term concerns as to the reliability of the bulk-power system. The regulations recognize that an emergency under Section 202(c) requires, first, "a *specific* inadequate power supply situation." 10 C.F.R. § 205.371 (emphasis added). The Department's non-specific dissatisfaction with regional power planning does not, consequently, empower the Department to override that planning by emergency order. The need for both specificity and certainty is repeated in the Department's regulations defining an inadequate energy supply: "A system may be considered to have" inadequate supply when "the projected energy deficiency . . . *will* cause the applicant [for a 202(c) Order] to be unable to meet its normal peak load requirements based upon use of all of its otherwise available resources so that it *is* unable to supply adequate electric service to its customers." *Id.* § 205.375 (emphasis added). The same provision suggests that an emergency will generally exist only when "the projected energy deficiency . . . without emergency action by the [Department], will equal or exceed 10 percent of the applicant's then normal daily net energy for load." *Id.*

The regulations further recognize that Section 202(c) does not provide a means of planning against months-off expectations or risks. They define an emergency as "an *unexpected* inadequate supply of electric energy which may result from the *unexpected* outage or breakdown" of generating, transmission, or distribution facilities—not a tool to ensure future energy abundance, or override state and private planning that the Department deems inadequate. 10 C.F.R. § 205.371 (emphasis added). Emergencies are characterized by shortages produced by "weather conditions, acts of God, or unforeseen occurrences not reasonably within the power of the affected 'entity' to prevent." *Id.* Where the culprit is increased demand, it must be "a *sudden* increase in customer demand," *id.* (emphasis added), rather than demand projections producing non-immediate reliability concerns.

And while the regulations suggest that "inadequate planning or the failure to construct necessary facilities can result in an emergency," they recognize that the Department may not utilize a "continuing emergency order" to mandate long-term system planning. *Id.* The regulations also recognize that "where a shortage of electricity is projected due solely to the failure of parties to agree to terms, conditions, or other economic factors" there is no emergency "unless the inability to supply electric service is *imminent*." *Id.* (emphasis added). An emergency may exist

where past planning failures produce an immediate, present-tense shortfall (that is where, a shortfall *results* from insufficient planning); the Department has no authority to commandeer bulk-system reliability planning merely because it deems current plans inadequate. See 10 C.F.R. § 205.375 (requiring present inability to meet demand to demonstrate inadequate energy supply). As the Department stated when it promulgated those regulations, the statute allows the Department to provide “assistance [to a utility] during a period of unexpected inadequate supply of electricity,” but does not empower it to “solve long-term problems.” *Emergency Interconnection of Elec. Facilities and the Transfer of Elec. to Alleviate an Emergency Shortage of Elec. Power*, 46 Fed. Reg. [39984](#), [39985](#)–86 (Aug. 6, 1981).

iv. Courts Have Uniformly Held that Section 202(c) Can Be Invoked Only in Immediate Crises.

Caselaw applying Section 202(c) further supports the narrow circumstances under which it permits the Department to seize command of the power system. *Richmond Power and Light* arose out of the 1973 oil embargo. The Federal Power Commission responded to the embargo by calling for voluntary transfer of electricity from non-oil power plants to areas of the country that relied heavily on oil, such as New England. 574 F.2d at 613. The New England Power Pool was not convinced that the voluntary program would work and petitioned the Commission for a 202(c) order. *Id.* Rather than issue such an order, the Commission facilitated an agreement between state commissions and supplying utilities, which satisfied the New England Power Pool, leading it to withdraw its petition. *Id.* A dissatisfied utility sought judicial review of the Commission’s decision to allow the withdrawal of the Section 202(c) petition. *Id.* at 614.

The court easily upheld the Commission’s decision not to invoke Section 202(c). *Id.* Though the oil embargo had ended, the utility argued that the “high cost and uncertain supply of imported oil” justified an emergency order. *Id.* The Commission countered that the voluntary program had worked, the New England Power Pool never interrupted service, and there was no need for a Section 202(c) order. *Id.* at 615. The D.C. Circuit agreed. *Id.* The utility alternatively argued that “dependence on imported oil leaves this country with a *continuing* emergency.” *Id.* (emphasis added). The court observed that Section 202(c) “speaks of ‘temporary’ emergencies, epitomized by wartime disturbances.” *Id.* Interpreting this statutory language, the court upheld the Commission’s view that Section 202(c) cannot be used when “supply is adequate but a means of fueling its production is in disfavor.” *Id.*

Richmond Power & Light thus teaches that Section 202(c) is not an appropriate means to implement long-term national policy to switch fuels. The provision allows only a temporary fix for a temporary problem.

The Eighth Circuit has similarly held that Section 202(c) can only be used to respond to immediate crises. In *Otter Tail Power*, a utility insisted that the only way for the Federal Power Commission to properly order the utility to connect to a municipal power provider was to issue a Section 202(c) order. 429 F.2d at 234. Demand for electricity in the city had increased, and the peak load of the municipal power provider was getting to be so high that both of its two generators would likely need to be used simultaneously in the near future, “causing a possible loss of service should one malfunction during a peak period.” *Id.* at 233–34. To avoid this possible loss of service, the Federal Power Commission issued a Section 202(b) order, requiring the utility to connect to the municipal power provider. *Id.* The utility argued that the Federal Power Commission used the wrong provision and should have used Section 202(c) instead. *See id.*

The court explained that Section 202(c) “enables the Commission to react to a war or national disaster” by ordering “immediate” interconnection during an “emergency.” *Id.* at 234. For non-emergency situations, “[o]n the other hand, Section 202(b) applies,” including when there is a “crisis which is likely to develop in the foreseeable future but which does not necessitate immediate action on the part of the Commission.” *Id.* The court upheld the Commission’s use of Section 202(b) instead of Section 202(c) because there was no immediate emergency. *See id.* The case law uniformly supports the interpretation that Section 202(c) can only be used in short-term, urgent emergencies.

v. The Department’s Prior Orders Recognize that Section 202(c) Does Not Confer Plenary Authority Over Bulk-System Resource Adequacy.

The Department’s consistent application of Section 202(c) before 2025 further corroborates the urgency of the emergency conditions that are the necessary predicate for any Department intervention under Section 202(c). *See Fed. Trade Comm’n v. Bunte Bros., Inc.*, 312 U.S. 349, 352 (1941) (“[J]ust as established practice may shed light on the extent of power conveyed by general statutory language, so the want of assertion of power by those who presumably would be alert to exercise it is equally significant in determining whether such power was actually conferred.”). Since obtaining authority under Section 202(c) in the 1970s and before 2025, the Department has consistently used Section 202(c) to address specific, imminent, and unexpected shortages—not to address longer-term reliability concerns or demand forecasts. *See, e.g.*, Ex. 9 at 1 (DOE Order No. 202-22-4) (responding to ongoing severe winter storm producing immediate and “unusually high peak load” between Christmas Eve and Boxing Day); Ex. 17 at 1–2 (DOE Order No. 202-20-2) (responding to shortages produced by ongoing extreme heat and wildfires); Ex. 105 at 1 (DOE Order No. 202-08-1) (ordering temporary connection of facilities in response to “massive devastation caused by Hurricane

Ike,” leaving “large portions” of Texas “without electricity”); *see also* Rolsma, 57 Conn. L. Rev. at 803–04 (describing “sparing[]” use of Section 202(c) outside of war-time shortages during the twentieth century).¹² Public Interest Organizations are not aware of any instance in which, before 2025, the Department utilized Section 202(c) to mandate generation the Department viewed as necessary to ensure long-term resource sufficiency, or in response to generalized regional risks that had not produced any particular, defined generation shortfall, and for good reason: Any such use would exceed the Department’s statutory authority.

2. *The Order Primarily Focuses on Long-Term Bulk-System Reliability, Which Is Not an Emergency Under Section 202(c), and Separately the Claimed Long-Term Emergency is Unreasonable and Not Based on Substantial Evidence.*

The Orders primarily rely upon assertions of long-term bulk-system reliability concerns. *See* Ex. 1 at 1–4 (December Schahfer Order); Ex. 2 at 1–4 (December Culley Order); Ex. 158 at 1-6 (March Schahfer Order) at 1-6; Ex. 159 at 1-6 (March Culley Order). Those concerns—even if fully substantiated—would not be a basis to mandate Culley’s and Schahfer’s continued operation. And they are not substantiated. MISO, the Indiana Commission, NIPSCO and CenterPoint Indiana have taken and are continuing to take steps to address longer-term concerns to ensure no resource shortfall arises.

i. *Even Assuming Arguendo Evidentiary Support, the Department’s Long-Term Concerns Are Not an “Emergency” Within the Meaning of 202(c).*

The Orders claim “a potential longer term resource adequacy emergency in MISO,” acknowledging a “capacity surplus for the summer of 2026,” but citing projections of possible “insufficient capacity to meet the peak demand for electricity in each of the following four summers”—that is, arising no earlier than the Summer of 2027. Ex. 1 at 3 (December Schahfer Order); Ex. 2 at 3 (December Culley Order); Ex. 158 at 5 (March Schahfer Order); Ex. 159 at 5 (March Culley Order) (also noting

¹² The Department has also narrowly tailored the remedies in Section 202(c) orders to ensure that the orders only address the stated emergency, to limit the order to the minimum period necessary, and to mitigate violations of environmental requirements and impacts to the environment. *See, e.g.*, Ex. 9 at 4–7 (DOE Order No. 202-22-4) (limiting order to the 3 days of peak load, directing PJM to exhaust all available resources beforehand, requiring detailed environmental reporting, notice to affected communities, and calculation of net revenue associated with actions violating environmental laws); Ex. 17 at 3–4 (DOE Order No. 202-20-2) (limiting order to the 7 days of peak load, directing CAISO to exhaust all available resources beforehand, requiring detailed environmental reporting).

“surplus of generation capacity” in the Winter of 2026, “followed by increasing deficits the following four years.”). Even if the Orders’ claimed emergency conditions were established (they are not), reliability concerns arising beyond “the near term . . . in subsequent years,” Ex. 1 at 4 (December Schahfer Order); Ex. 2 at 5 (December Culley Order) Ex. 158 at 8 (March Schahfer Order); Ex. 159 at 8 (March Culley Order), do not qualify as an emergency under Section 202(c). Such concerns are neither imminent nor unexpected. The Department’s stated concerns cannot plausibly be characterized as a “*sudden* increase in the demand for electric energy” or a “shortage” in electric energy, generation, or transmission” constituting an emergency. 16 U.S.C. § 824a(c)(1).

At most, the Orders describe long-term trends that may affect the reliability of the bulk power system in the future if left unaddressed. The Orders’ longer-term concerns are based on projections of demand increases, changes in the mix of power supply resources, challenges in resource development, and the Administration’s view of foreign actors. *See* Ex. 1 at 1–4 (December Schahfer Order); Ex. 2 at 1–4 (December Culley Order); Ex. 158 at 1-5 (March Schahfer Order); Ex. 159 at 1-5 (March Culley Order).

While many of the Orders’ stated concerns are the province of state, regional, and private entities, Congress has provided certain mechanisms for the federal government to address the reliability concerns raised in the Orders. The emergency provision in Section 202(c), along with the Department’s claimed power to seize command-and-control authority over generating resources like Schahfer and Culley 2, are not among those mechanisms.

The congressionally provided mechanisms to the federal government include Section 202(a), which allows the federal government to pursue “an abundant supply of electric energy” but only by facilitating “*voluntary* interconnection and coordination of facilities for the generation, transmission, and sale of electric energy” 16 U.S.C. § 824a(a) (emphasis added). Additionally, under certain circumstances, Section 202(b) allows the federal government to require utilities to sell or exchange energy with other facilities, but only upon application and with “no authority to compel the enlargement of generating facilities for such purposes.” *Id.* § 824a(b).

Another mechanism, Section 215, provides for mandatory, nationwide reliability standards developed and enforced by a federally certified but independent entity. 16 U.S.C. § 824o(d), (e). “These standards,” the Department explains, “ensure that all owners, operators, and users of the bulk-power system have an obligation to maintain system security and reliability.” Ex. 52 at 7 (Department Export Authorization EA-365-C (Oct. 21, 2025)). The standards cannot be enforced by ordering generation facilities to operate, and Section 215 specifically disallows requiring the “construction

of additional generation” or “enforc[ing] compliance” with “adequacy” standards. 16 U.S.C. § 824o(e), (i)(2).

The Orders purport to mandate generation based upon the Department’s assessment of the bulk-power system’s long-term reliability needs, a power Congress chose not to provide *any* federal agency. *See* 16 U.S.C. § 824o(e) (specifying enforcement mechanisms for federal reliability standards). And what authority Congress has authorized to implement mandatory reliability standards, it provided to FERC—not the Department. *Alcoa*, 564 F.3d at 1344. Reliability concerns in future years simply do not constitute an emergency within the meaning of Section 202(c).

Section 202(c) provides an explicitly “temporary” authority, 16 U.S.C. § 824(a)(c), preventing any interpretation of its terms that might encompass a potential longer term resource adequacy emergency. The expansive interpretation of Section 202(c) implicit in the Orders, stretching the meaning of “emergency” to cover resource planning concerns over “years” beyond the near term, is further precluded by the Federal Power Act’s express background principles of permitting “Federal regulation” only of “matters which are not subject to regulation by the States,” and disavowing “jurisdiction, except as specifically provided” over “facilities used for the generation of electric energy.” 16 U.S.C. § 824(a), (b)(1); *see Duke Power Co. v. Fed. Power Com.*, 401 F.2d 930, 938 (D.C. Cir. 1968) (explaining that the Federal Power Act’s policy declarations are “relevant and entitled to respect as a guide in resolving any ambiguity or indefiniteness in the specific provisions which purport to carry out its intent”). The Department knows that “resource adequacy planning and capacity requirements . . . have traditionally been the domain of state regulatory commissions, NERC-certified Regional Entities, and RTOs/ISOs,” *i.e.*, not the Department. Ex. 52 at 5 n.4 (Department Export Authorization EA-365-C (Oct. 21, 2025)).

Through the Orders, the Department expressly seeks to override the decisions of state, regional, and utility planners pursuant to the procedures established by Congress to ensure abundant electricity supplies and the reliability of the bulk-electric system. 16 U.S.C. §§ 824a(a)–(b), 824o. Section 202(c) does not permit that effort to transform the statutory scheme from one driven primarily by market- and state-based decision-making to one consolidating centralized federal command-and-control in the Department. And it especially does not permit that transformation in service of the Department’s desire to dictate “how much coal-based generation there should be over the coming decades”—a power that the Supreme Court has found Congress “highly unlikely” to have left to agency discretion. *West Virginia v. EPA*, 597 U.S. 697, 729 (2022).

ii. The Order Does Not Demonstrate Any Long-Term Resource Adequacy Concerns that Are Not Already Being Addressed Through the Appropriate Processes Under the Federal-State Balance of Responsibilities.

In addition to being an invalid basis for Department action under Section 202(c), the Orders' discussion of long-term concerns is unreasoned and without substantial evidence, including because the Orders both overestimate the potential of a shortfall and undervalue the ability of existing processes to address any projected shortfall. The following sections examine the several bases for the Department's claim of a long-term emergency; as they explain, none of those bases provide any actual evidence that Department intervention is necessary.

a. The Department Misinterprets the OMS-MISO Survey.

One of the Department's principal citations for its claim that MISO faces a long-term shortfall is the OMS-MISO Survey. Ex. 1 at 3 (December Schahfer Order); Ex. 2 at 3 (December Culley Order); Ex. 158 at 5 (March Schahfer Order); Ex. 159 at 5 (March Culley Order) (discussing Ex. 89 at 2, 7, 9 (2025 OMS-MISO Survey)). The Department's description of the OMS-MISO Survey is fundamentally flawed.

Broadly speaking, the purpose of the OMS-MISO Survey is to explore a wide range of potential outcomes based on current trends, to ensure that MISO is aware of the full spectrum of possibilities (including remote ones) for which it may need to secure adequate resources to ensure grid reliability. See *supra* section IV.B.3 (discussing the OMS-MISO Survey). In keeping with that purpose, the Survey applies assumptions to the bottom end of its forecasts that are extremely unlikely to reflect reality. This worst-case scenario contains extremely conservative assumptions about how much of the new generation that utilities have actively planned for is able to become operational. See Ex. 89 at 5–6 (2025 OMS-MISO Survey).

The Department creates the illusion of a long-term emergency by citing only to this bottom edge, studiously ignoring the rest of the range of outcomes that were considered. In short, the Department cherry-picks the data in the Survey that confirm the Department's own biases.

No example of the Department's selective interpretation of the evidence is more obvious than the Department glossing over the fact that the OMS-MISO Survey projects a near-certain surplus of resources through at least May 2027. See Ex. 1 at 3 (December Schahfer Order); Ex. 2 at 2–3 (December Culley Order); Ex. 158 at 5 (March Schahfer Order); Ex. 159 at 5 (March Culley Order). In other words, the Department's own citation provides no basis to think that Schahfer or Culley are needed for over a year. The Department attempts to undermine this projection by

calling it “potential” and suggesting that “at least 3.1 GW of additional generation capacity” would need to be added. *Id.* But this phrasing is not consistent with the study, in which the most conservative estimate concludes there will be a surplus in 2026; and the phrasing ignores the reality that new resources are built in MISO every year. 3.1 GW is fewer resources than came online per year over the past three years, and that was before utilities began accelerating new resource development in response to increasing load projections. *See* Ex. 89 at 6 (2025 OMS-MISO Survey). The Department’s claim that MISO needs at least 3.1 GW of new generation is also factually incorrect because it ignores 1.4 GW of existing resources that are not currently committed to retire, but which were excluded from the Survey’s projections because they were identified as having a “low certainty” of continued operation in 2026—if even one of those resources doesn’t end up retiring, it would reduce the need for new resources below 3.1 GW. Ex. 89 at 5, 7 (2025 OMS-MISO Survey).

The Department’s discussion of later-year projections is even more misleading. *See* Ex. 1 at 3 (December Schahfer Order); Ex. 2 at 3 (December Culley Order); Ex. 158 at 5 (March Schahfer Order); Ex. 159 at 5 (March Culley Order). The OMS-MISO Survey examines MISO’s resource adequacy projections using two alternate assumptions for how quickly new resources can be built. The first assumption relies on a “historical” projection. The historical projection predicts 3.5 GW of new resources per year based on a three-year historical average, plus 1.2 GW of replacement resources per year based on historical levels. The Survey’s “historical” projection also assumes that only half of utilities’ planned upgrades to existing facilities will actually take place. Ex. 89 at 5, 7 (2025 OMS-MISO Survey).

The second assumption relies on an “emerging” projection “based on member submittals to the OMS-MISO Survey” (*i.e.*, what utilities have told OMS-MISO they are actually planning to build). The emerging projection predicts 6.2 GW of new resources per year and 2.4 GW of replacements per year. Ex. 89 at 5–6 (2025 OMS-MISO Survey).

The Department cites exclusively to the “historical” projection, ignoring the “emerging” projection entirely—but this paints an excessively pessimistic picture of the future. The Survey’s estimated 1.4 to 8.2 GW deficits from 2027/28 to 2030/31 in the historical projection are more than matched by its forecast 6.4 to 11.4 GW surpluses over the same period in its emerging projection. *Id.* at 7. And again, both of these projections ignore entirely the possibility that any of the 1.4 to 3.8 GW of “potentially unavailable resources” turns out to in fact still be available. The Department’s decision to ignore the half of the OMS-MISO Survey that is inconsistent with its emergency declaration has no basis in the structure of the

Survey: the two projections are explicitly presented as “bookend capacity forecasts.” *Id.* at 6.

By ignoring the emerging projection, the Department unreasonably fails to take into account several key factors that support that projection. First, the historical 2022 to 2024 new capacity build rate is not likely to be reflective of future build because the scope of the need for new generation only became clear in the past year or two: indeed, MISO added almost 5 GW of new resources in 2024, which was about 50 percent more than the MISO region had ever built before. *Id.* Second, the historical projection underestimates future contributions of storage, because MISO currently only has roughly 164 MW of operational storage, meaning that the historical trend still does not account for the coming influx of battery storage resources. And third, the historical projection’s assumption that only half of utilities’ “replacement” and “surplus” projects will actually occur has no actual historical basis, because these are new categories of projects that MISO therefore has no historical data on. *Id.* at 5 (indicating that replacement and surplus projects were not considered for the 2024 Survey).

The Department has also ignored other information in the OMS-MISO Survey that indicates the possibility of even more new generation coming online than either of the two projections in the Survey anticipate. For instance, the survey indicates that 54 GW of projects have a signed generator interconnection agreement but are waiting to interconnect. *Id.* at 6. A review of historic trends is instructive here: ninety percent of projects with signed generator interconnection agreements ultimately get built. See Ex. 120 at 6 n.* (2024 OMS-MISO Survey). Assuming that trend continues—and the circumstances of increasing demand provide good reason to think it will—48 GW of the total 54 GW projects currently with signed generator interconnection agreements will come online.

Additionally, there are about 291 GW of projects in MISO’s interconnection queue. Ex. 121 at 7:15–17 (Witmeier 2025 ERAS Testimony). MISO’s historic interconnection queue completion rate is twenty-one percent, see Ex. 112 at 21:2–5 (Witmeier 2024 Queue Cap Testimony), which would equate to another 61 GW ($291 \text{ GW} \times 21\% = 61.1 \text{ GW}$) of new projects interconnecting from the current queue. Together, those two groups represent more than 109 GW of new resource additions that MISO could reasonably expect to come online in the next several years.

- b. Neither the Energy Emergency Executive Order nor the Grid Reliability Executive Order provides a valid basis to declare an emergency under Section 202(c).

The Department also cites to the Energy Emergency EO and the Grid EO claiming that there is an energy emergency and that the grid is being stressed by

unprecedented demand. Ex. 1 at 3–4 (December Schahfer Order); Ex. 2 at 3 (December Culley Order); Ex. 158 at 6–7 (March Schahfer Order); Ex. 159 at 6–7 (March Culley Order). Neither of these executive orders is valid evidence of an actual energy emergency.

If the Orders’ reference to a national energy emergency is meant to serve as evidence of an emergency as defined under Section 202(c), it is insufficient. Claims recited in an Executive Order are not substantial evidence supporting agency action. Substantial evidence is “such relevant evidence as a reasonable mind might accept as adequate to support a conclusion.” *Chritton v. Nat’l Transp. Safety Bd.*, 888 F.2d 854, 856 (1989) (internal quotation marks omitted). And an emergency under Section 202(c) must be a specific inadequate power supply situation. See *supra* sec. V.A.1; *e.g.*, 10 C.F.R. § 205.371 (emphasis added). In the quoted passages from the Energy Emergency EO, the President offered his perspective on issues relating to the nexus between energy usage and “our Nation’s economy, national security, and foreign policy.” But these themes are simply not relevant to assessing whether an “emergency” exists under Section 202(c)(1) and the Department’s regulations under 10 C.F.R. § 205.371. Thus, the Orders provide no specific evidence of inadequate generation nationwide, let alone in Indiana or even in MISO specifically. An emergency under Section 202(c) also must be imminent. See *supra* sec. V.A.1. But even the Department’s other cited evidence demonstrates clearly that there is nothing imminent about even the most tenuous projected shortfalls. Nothing in the Orders refers to a shortage in the actual time period covered by the Orders.

Even if the declared national energy emergency were legitimate, a presidential declaration of an emergency does not unlock unlimited agency powers. See *Biden v. Nebraska*, 600 U.S. 477, 500-01 (2023) (presidential declaration of national emergency does not change the limitations on agency’s emergency authority as written into statute). President Trump issued the Energy Emergency EO pursuant to authority from the National Emergencies Act.¹³ Congress explained that the

¹³ Under the National Emergencies Act, no emergency powers unlocked by a Presidential declaration of a national emergency “shall be exercised unless and until the President specifies the provisions of law under which he proposes that he, or other officers will act.” 50 U.S.C. § 1631 (emphasis added). The Energy Emergency EO does not adhere to this requirement. Ex. 92, 90 Fed. Reg. at 8,434 (Energy Emergency EO) (generically directing agencies to “identify and exercise any lawful emergency authorities available to them, as well as all other lawful authorities they may possess, to facilitate the . . . generation of domestic energy resources.”).

National Emergencies Act “is not intended to enlarge or add to Executive power. Rather, the statute is an effort by Congress to establish clear procedures and safeguards for the exercise by the President of emergency powers conferred on him by other statutes.” S. Rep. No. 94-1168, 3 (1976), (emphasis added). But Section 202(c)’s authority is not triggered by a Presidential emergency declaration; the statute requires that “the Commission determine[] that an emergency exists.” 16 U.S.C. § 824a (emphasis added).¹⁴ Thus, the burden is on the Department to demonstrate that there is an emergency pursuant to the narrow language of Section 202(c); simply pointing to the Energy Emergency EO or the Grid Reliability EO without providing actual evidence that an emergency exists results in an arbitrary and capricious order.

c. The Department’s July 2025 Resource Adequacy Report does not substantiate its claim of a long-term resource adequacy shortfall.

The Orders also briefly cite to the Department’s July 2025 Resource Adequacy Report as evidence of a potential emergency years down the road. Ex. 1 at 4 (December Schahfer Order); Ex. 2 at 4 (December Culley Order); Ex. 158 at 7 (March Schahfer Order); Ex. 159 at 7 (March Culley Order) (citing Ex. 96 (July 2025 Resource Adequacy Report)). But that Report does not credibly project conditions in 2030 because of its many inaccurate assumptions and methodological errors.¹⁵ Moreover, that Report offers no actual evidence of any near-term shortfall.

Most glaringly, the Report overestimates demand growth and expected facility retirements while underestimating the likelihood of new entry. This biases the entire report in the direction of over-identifying resource adequacy concerns. Ex. 113 at 21–25 (Inst. Pol’y Integrity Report); see also Ex. 68 at 7 (Grid Strategies Sept. Report) (explaining that the July 2025 Resource Adequacy Report relies on load growth and capacity retirement assumptions that are “drastically higher” than those provided by the U.S. Energy Information Administration, the arm of the Department tasked with “independent statistics and analysis”); Ex. 122 at 2–3 (GridLab Report) (noting that the July 2025 Resource Adequacy Report fails to account for the potential flexibility of data center load additions; that the Report assumes double the retirements and only a quarter of the firm resource additions

¹⁴ The Department has exercised certain powers under Section 202(c) since the DOE Organization Act of 1977. 42 U.S.C. § 7151(b).

¹⁵ A group of organizations including several of the PIOs here have raised several concerns with this Report in a separate rehearing request. See generally Ex. 99 (RFR of July Resource Adequacy Report).

assumed by the Energy Information Administration; and that the report ignores “fast-track” interconnection processes recently approved by FERC for multiple RTOs); Ex. 99 at 34-35 (PIOs’ RFR of July Resource Adequacy Report) (citing multiple expert reports and initiatives demonstrating the potential for flexibility of large data center loads, including Ex. 123 (Duke University Rethinking Load Growth Study)).

The Report also “departs from best [modeling] practices by using a deterministic modeling rather than a probabilistic approach,” and thereby fails to account for necessary uncertainties. Ex. 113 at 19 (Inst. Pol’y Integrity Report). And in many places the Department simply does not explain its own methodology. The report states that its model is derived from NERC’s Interregional Transfer Capability Study, which is focused on the ability of the transmission system to transfer power between regions. Ex. 96 at 2 (July 2025 Resource Adequacy Report). However, the report inexplicably excludes new transmission projects from its analysis, ignoring that transmission improvements can be the most cost-effective way to improve grid reliability. The Department’s report also appears to misunderstand certain principles of statistical reasoning, calling out PJM for failing loss-of-load criteria under one realization of a possible weather year that would include Winter Storm Elliott, without considering that a system’s LOLE is averaged across all simulated weather years. Ex. 113 at 19 (Inst. Pol’y Integrity Report); Ex. 96 at 7, 9, 27 (July 2025 Resource Adequacy Report). The Department also added more “perfect capacity” (in megawatts) within its modeling than actually needed to bring regions to its targeted Normalized Unserved Energy level. Ex. 113 at 26 (Inst. Pol’y Integrity Report); Ex. 96 at 19, 27, 30, 32, 40 (July 2025 Resource Adequacy Report). These analytical failings in and of themselves disqualify the report as a viable source of evidence for an emergency finding.

The lack of evidence for a long-term emergency is underscored by the fact that the Department’s own analysis premises a resource adequacy shortfall on a type of demand increase (large load buildout), Ex. 96 at 2–3, 15–17 (July 2025 Resource Adequacy Report), that the report goes on to admit would likely never actually be allowed to destabilize the grid. Specifically, the report notes that its analysis “is not an indication that reliability coordinators would allow this level of load growth to jeopardize the reliability of the system.” *Id.* at 14. In other words, even taking the report at face value, it does not identify a shortfall of a type and nature that could ever justify invocation of the Department’s Section 202(c) emergency authority. At best, the report highlights that data centers cannot be built at projected rates unless new generation is built, which is far from the type of emergency situation that could ever provide the basis for a Section 202(c) order.

Finally, on its opening page, the report acknowledges that its analysis is general in nature, looking at the country as a whole, and that the various “entities responsible for the maintenance and operation of the grid” have information “that could further enhance the robustness of reliability decisions” in the sections of the grid they administer. *Id.* at i. This type of generalized analysis based on incomplete information is simply insufficient to justify a Section 202(c) emergency finding for MISO or any other specific region.

d. MISO has designed its ERAS proposals to address claimed shortfalls and has not suggested that any further generation/capacity is needed.

There is one place where MISO has projected a distant resource adequacy need: in the course of requesting FERC approval for its proposed Expedited Resource Addition Study, which FERC approved in July 2025. Ex. 90 at 6, 13–17 (MISO ERAS Transmittal Letter); Ex. 91 (MISO ERAS Decision). But, as explained above, sec. IV.B.3, that projected need spurred MISO to initiate a process that will add at least 26.5 GW (and likely more) of new capacity to MISO’s system over the next several years.

The Department minimizes the import of this approval by suggesting that the projects won’t reach commercial operation for at least three years and could be further delayed by supply chain constraints. Ex. 1 at 3 (December Schahfer Order); Ex. 2 at 3 (December Culley Order); Ex. 158 at 6 (March Schahfer Order); Ex. 159 at 6 (March Culley Order). But the Department’s first statement is factually incorrect—projects that are selected for ERAS could begin operation sooner than three years from the application date; they just have up to six years of leeway—and its second statement is far too conjectural to provide a basis for an emergency declaration. Ex. 91 at P 84 (MISO ERAS Decision). The Department cannot defensibly declare an emergency justifying use of its 202(c) authority based on a concern that the expedited interconnection process MISO has established specifically to meet projected resource adequacy needs won’t work—absent substantial and specific evidence of that fact, it is pure conjecture.

e. The North American Electric Reliability Corporation’s Recent Assessment Does Not Support the Claimed Long-Term Emergency.

The March Schahfer and Culley Orders’ reliance on the 2025 Long-Term Reliability Assessment published in January 2026 by NERC as evidence supporting the claimed emergency is also inapposite. Ex. 158 at 6-7 (March Schahfer Order); Ex. 159 at 6-7 (March Culley Order). The report discloses on its face that, for example, it took no consideration of the ERAS interconnection process. Ex. 177 at 8, 15 (NERC Jan. 2026 LTRA). “If ERAS projects come in as currently planned, the projected reserve margin shortfall would be eliminated.” *Id.* at 15. The report also

lists no elevated risk for the year 2026, which covers the time period of the March Schahfer and Culley Orders. *Id.* at 8. The Department could have and should have accounted for those factors. The report also acknowledges that state regulators and utilities are “statutorily required to ensure reliability” and generally work to align large load additions, generator retirements, and generator additions. *Id.* at 15.

Expert analysis of the Long-Term Reliability Assessment reveals other shortcomings as well. The Assessment failed to consider *any* generation which has begun, but not yet completed system studies, Ex. 166 at 11 (Grid Strategies LTRA Review). Failing to include even a fraction of these resources currently in the queue is unrealistic, and improperly suggests resource shortfalls by wholesale ignoring the resources that will add additional capacity to the system. A more realistic analysis that discounts resources in the study process by historic dropout rates found that MISO is on pace to add enough generation to maintain resource adequacy. *Id.* at 12. Likewise, the Assessment did not account for chip-industry manufacturing limitations in its forecast of data center load, or how data center load flexibility could decrease capacity demands of data center expansion. *Id.* at 19–24. The result of these oversights is an assessment which likely overstates risk. *Id.* at 31 (showing the MISO region as being on track to meet capacity needs in 2030).

f. The Generic Testimony of a Single MISO Executive on which the Department Relies Is Contradicted by Numerous More Concrete Statements by MISO.

Finally, the March Schahfer and Culley Orders cite to testimony by Jennifer Curran, a current MISO executive, that speaks in general terms about MISO’s need for capacity. Ex. 158 at 7–8 (March Schahfer Order); Ex. 159 at 7–8 (March Culley Order) (citing Ex. 178 (Curran Testimony)). As an initial matter, Ms. Curran’s testimony is sufficiently vague that it is open to any number of interpretations. Her testimony provides no timeline for the risk she communicates, nor does it state how great the reliability risk is, or how much bigger it could get, from the various systemic trends she discusses. *See* Ex. 178 at 4–6 (Curran Testimony). This generic testimony is taken from an opening statement to Congress; it is also several steps removed from the concrete, tangible, and specific evidence that is necessary for the Department to find that there is a resource adequacy emergency.

The March Schahfer and Culley Orders’ treatment of Ms. Curran’s testimony is a prime indicator of unreasoned decision-making because it misrepresents aspects of the testimony, cherry-picks only favorable statements while omitting unfavorable statements, and wholly ignores related evidence undercutting the Department’s position. For example, the ~~November~~ Orders misrepresent Ms. Curran’s testimony in suggesting she “acknowledged the Nation’s current energy crisis.” Ex. 158 at 7

(March Schahfer Order); Ex. 159 at 7 (March Culley Order). In fact, Ms. Curran never said or implied that there is any crisis or emergency. Moreover, the Department conspicuously omits elements of her testimony cutting against the Department's invocation of Section 202(c) authority. For example, Ms. Curran testified that "[i]mproving existing market and operations processes tool is a cost-effective and timely way to improve reliability in an efficient manner." Ex. 178 at 7 (Curran Testimony). She further testified that the risks of generation plant retirements can be addressed by allowing *local* reliability requirements to determine the pace of retirements. *Id.* Ms. Curran's recommendations for future action do not include the Department's use of Section 202(c) orders, nor do they include coal-fired power generation. *See id.* at 9–10.

The March Schahfer and Culley Orders also fail to mention or consider statements by other MISO executives rebutting the Department's conclusion that there is a resource adequacy deficiency. For instance,

In a statement, MISO said it will "continue coordinating with Consumers Energy to comply with the [Campbell 202c Orders]." But MISO again stressed that J.H. Campbell did not clear the planning resource auction and is unnecessary for resource adequacy in the 2025/26 planning year. "MISO's 2025–2026 Planning Resource Auction indicated adequate resources to meet anticipated demand. . . .," MISO spokesperson Brandon Morris said in a statement to RTO Insider.

Ex. 117 (RTO Insider Article on August Order). The March Schahfer and Culley Orders further ignore testimony from MISO's Internal Market Monitor at a FERC technical conference that MISO "[was] more than adequate" for the Summer of 2025 and that the IMM has no substantial resource adequacy concerns "in the near term." Ex. 35 at 2 (Patton MISO Comments). The Internal Market Monitor was even more candid when he stated in March 2026 with respect to the Orders that, "It's pretty easy to come the conclusion that none of these orders are actually needed." Ex. 179 at PDF p. 2 (RTO Insider March 2026 Article). Finally, the Orders fail to consider that MISO has never requested that a 202(c) order be issued to Schahfer or Culley.

3. The Orders Do Not, and Could Not, Provide any Valid Evidence or Reasoned Decision-Making to Support Their Stated Near-Term Resource Adequacy Concerns.

The claimed near-term emergency in the Orders is unspecific. And none of the sources cited in the Orders, separately or together, establishes factual circumstances that come close to a near-term emergency or otherwise meet the definition of "emergency" that permits Departmental action under Section 202(c). 16

U.S.C. § 824a(c)(1). The Orders also rely on these sources in a vacuum, failing to consider many other analyses of which the Department is aware or should be aware. The Orders’ near-term emergency determination is unjustified, unreasoned, and not based on substantial evidence.

i. The Described Concerns Are Insufficiently Specific and Certain to Meet the Statutory Definition of an Emergency.

The Orders gesture at the possibility of electricity shortfalls in the “near” term, but offer no plausible evidence of such shortfalls. See *infra* sec. V.A.3.ii.

That failure to adduce plausible evidence to one side, the generalized, speculative risks described by the Orders are neither specific nor certain enough to qualify as an “emergency” within the meaning of Section 202(c). 16 U.S.C. § 824a(c). A notional suggestion of some possible shortfall, which might (or might not) require generation from Schahfer or Culley 2, is not a “specific inadequate power supply situation” enabling the use of the Department’s Section 202(c) authority. 10 C.F.R. § 205.371.

The Department does not find that there will be a single supply shortfall during the entirety of each 90-day term of the four recently issued orders. Ex. 1 at *passim* (December Schahfer Order); Ex. 2 at *passim* (December Culley Order); Ex. 158 at *passim* (March Schahfer Order); Ex. 159 at *passim* (March Culley Order). Nor does the Department point to any specific circumstances even giving rise to a risk of such a shortfall. Ex. 1 at *passim* (December Schahfer Order); Ex. 2 at *passim* (December Culley Order); Ex. 158 at *passim* (March Schahfer Order); Ex. 159 at *passim* (March Culley Order). For the duration of the four Orders—from December 23, 2025 through March 23, 2026 and March 24, 2026 through June 21, 2026—the Department’s near-term justification amounts to the simple assertion that “MISO’s year-round resource adequacy concerns are well documented.” See Ex. 1 at 1 (December Schahfer Order); Ex. 2 at 1 (December Culley Order); Ex. 158 at 2 (March Schahfer Order); Ex. 159 at 2 (March Culley Order). At most, this conclusory statement asserts the possibility that some resource inadequacy might (or might not) emerge somewhere in MISO—but that does not, and cannot, demonstrate that “an emergency exists by reason of a sudden increase in the demand for electric energy” or an identified “shortage of electric energy” or of “facilities for the generation or transmission of electric energy.” 16 U.S.C. § 824a(c)(1); see also *Louisville & N.R. Co. v. Sullivan*, 617 F.2d 793, 795 (D.C. Cir 1980) (explaining that where statute permits emergency orders based on determination that a “facility or piece of equipment [is] in unsafe condition, the agency may not issue order based on “a generalized poor safety record” without showing of “particular” safety hazard). The Orders do not describe or provide

support for—even taken on their own terms—any imminent, specific, or certain electricity shortfall. The Orders therefore fail to describe an “emergency” within the meaning of Section 202(c).

ii. The Claimed Shortfall Is Unreasonable and Not Supported by Substantial Evidence.

The Orders fail to employ reasoned decision-making and fail to offer substantial evidence of an emergency in the Spring 2026 season (which is most of the period it covers) or the upcoming Summer 2026 season. Instead, the Orders review and recite information from several MISO documents, misinterpreting and misrepresenting the materials to allege a resource adequacy crisis that simply does not exist. The Orders also misstate grid conditions during the recently completed Winter 2025–2026 season.

The first example of this flawed reasoning is the Orders’ statement 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.” Ex. 1 at 2 (December Schahfer Order) (quoting Ex. 31 at 13 (MISO 2025–26 Auction Results)); Ex. 2 at 2 (December Culley Order) (quoting same); Ex. 158 at 5 (March Schahfer Order) (quoting same); Ex. 159 at 5 (March Culley Order) (quoting same). As in prior Section 202(c) orders last year, *e.g.*, Ex. 124 at 2 (November Campbell Order), the Department fails to note that this statement referred to *offers* rather than available supply, and particularly only to the netting of additions and subtractions causing total North/Central offers to decrease in absolute terms from Summer 2024 to Summer 2025. *See* Ex. 31 at 13 (MISO 2025–26 Auction Results). The Department also fails to acknowledge that overall resource offerings in MISO North/Central were sufficient relative to the Reserve Margin Requirement, which also decreased from 2024 to 2025. *Compare* Ex. 84 at 16 (MISO 2024–25 Auction Results) (showing a Summer 2024 Reserve Margin Requirement of 100,710 MW in Zones 1–7), *with* Ex. 31 at 18 (MISO 2025–26 Auction Results) (showing a Summer 2025 Reserve Margin Requirement of 99,770.5 MW in Zones 1–7).

This result also tracks MISO’s Planning Auction results which, as explained above, *supra* secs. IV.A.2.ii, IV.B, resulted in MISO securing more resources for Spring 2026 than it determined were necessary to ensure resource adequacy. In short, it was clear in April 2025, when MISO released its 2025–2026 Planning Auction results, that the MISO system had no resource adequacy crisis this Spring even after accounting for announced plant retirements, including the Schahfer and Culley retirements. The Orders fail to acknowledge these critical facts undercutting the Orders’ emergency determination.

The Orders also gesture to various recent reports in which MISO has forecasted an increasing resource adequacy risk in non-Summer seasons. See Ex. 1 at 1–2 (December Schahfer Order); Ex. 2 at 1–2 (December Culley Order); Ex. 158 at 4 (March Schahfer Order); Ex. 159 at 4 (March Culley Order). However, the Department does not appear to have carefully examined what MISO was actually saying in any of these materials.

First, the Department quotes from MISO’s 2021 capacity accreditation filing, in which MISO described a shift of reliability risks “from ‘Summer only’ to a year-round concern,” apparently for the proposition that the Winter and Spring seasons also experience meaningful systemic risks. Ex. 1 at 1 (December Schahfer Order) (quoting Ex. 77 at 3 (MISO 2021 Transmittal Letter)); Ex. 2 at 1 (December Culley Order) (quoting same); Ex. 158 at 2 (March Schahfer Order) (quoting same); Ex. 159 at 2 (March Culley Order) (quoting same). The relevant graph in the 2021 Transmittal Letter shows an incidence of MaxGen events across all four seasons from 2014 through 2022 but says nothing about how serious these events were. See Ex. 77 at 3 (MISO 2021 Transmittal Letter). A simple review of MISO’s actual MaxGen events would have revealed that none of the Winter events exceeding the “MaxGen Warning” level ascended to the level (MaxGen Event Step 5) that entails manual shedding of load. Ex. 32 at *passim* (MISO Emergency Declarations); see *supra* sec. IV.A.3, IV.B.1. In other words, recent winter storms have presented a challenge for MISO—but even the most severe episodes in recent years have failed to cause actual load shedding. And as explained above, MISO’s own assessment is that the Winter does not yet have anything close to the grid vulnerability of Summer. The Orders also say absolutely nothing about system risks specific to the Spring season.

Next, the Orders cite MISO’s 2023 Attributes Roadmap, which (according to the Orders) established that “by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons” and “the risk of loss of load in the winter and spring seasons, although not as high as in the summer or fall, will nevertheless increase over time.” Ex. 1 at 2 (December Schahfer Order) (citing Ex. 85 at 11 (MISO Attributes Roadmap)); Ex. 2 at 1–2 (December Culley Order) (citing same); Ex. 158 at 3 (March Schahfer Order) (citing same); Ex. 159 at 3 (March Culley Order) (citing same). But again, the Orders fail to discuss the magnitude of risk at issue. The implicated graph on page 11 of the MISO Attributes Roadmap identifies loss of load risks that peak around hour 20 with around 150 hours of expected lost load, Ex. 85 at 11 (MISO Attributes Roadmap), but those 150 hours (from 3,750

runs of the model)¹⁶ correspond to a lower risk than the industry-standard acceptable risk target. Specifically, the LOLE risk is .05 days/year, or 50% of the industry-standard target of 0.1 days per year. Ex. 86 at 7, 19 (MISO Attributes Roadmap Technical Appendix); *see generally* Ex. 10 at 2–3 (Grid Strategies June Report) (discussing LOLE risk targets). The Department thus fails to make a reasoned determination and fails to account for record evidence detracting from its determination, because its discussion of “equal” risk fails to mention that the absolute risk in both seasons remains extremely low.

Furthermore, the graph that the Orders cite in the MISO Attributes Roadmap does not even refer to the present Spring seasons. *See* Ex. 85 at 11 (MISO Attributes Roadmap). Instead, it refers to projected risk in Winter 2027–28 and makes clear that there was minimal such risk in Winter 2023–24; but it is entirely silent as to the risk profile in Winter 2025–26, which is the only season that is remotely relevant to the Orders’ claim of a near-term emergency. *See id.* And the resource mix for Winter 2025–26 looks much more similar to that in Winter 2023–24 (when risk was not concentrated in the Winter season) than to MISO’s projected Winter 2027–28 mix—so the 2023 chart is a more useful predictor of likely risk allocation in Winter 2025–26. *See* Ex. 68 at 1–2 (Grid Strategies Sept. Report). As further discussed below, the Orders may not use the possibility of risks in future Winter or Spring seasons as evidence that actual risks exist in the current Spring season—particularly where, as here, there is concrete evidence demonstrating that no such risk exists.

Finally, the Orders gesture to MISO’s 2024 Reliability Imperative Report, which mentions “risks in non-summer months that rarely posed challenges in the past.” Ex. 1 at 2 (December Schahfer Order) (quoting Ex. 87 at 12 (MISO’s Response to the Reliability Imperative)); Ex. 2 at 2 (December Culley Order) (quoting same); Ex. 158 at 4 (March Schahfer Order) (quoting same); Ex. 159 at 4 (March Culley Order) (quoting same). But the “Response to the Reliability Imperative” offers no specific information about Winter and Spring season risks other than its qualitative discussion of recent winter storms. *See generally* Ex. 87 at *passim* (MISO’s Response to the Reliability Imperative).

Additionally, the Department’s own export authorizations undercut the claimed emergency. The Department has continued to grant entities the authority to export power from parts of MISO into Canada. *See* Department Export Authorizations

¹⁶ For a given season, 15 weather years and 250 random outage samples per weather year are modeled. Ex. 86 at 7 (MISO Attributes Roadmap Technical Appendix). $15 \times 250 = 3,750$.

Library, <https://www.energy.gov/oe/export-authorization-library> (last visited Apr. 19, 2026); *e.g.*, Ex. 2-52 at 11–12 (Department Export Authorization EA-365-C (Oct. 21, 2025)) (authorizing exports from multiple interconnection points in Michigan and Minnesota).

Under Section 202(e), the Department shall approve an authorization to export power “unless, after opportunity for hearing, it finds that the proposed transmission would impair the sufficiency of electric supply within the United States or would impede or tend to impede the coordination in the public interest of facilities subject to the jurisdiction of the Commission.” 16 U.S.C. § 824a(e). The Department interprets the “sufficiency” prong of Section 202(e) “to mean that sufficient generating capacity and electric energy must exist such that the export could be made without compromising the energy needs of the exporting region, including serving all load obligations in the region while maintaining appropriate reserve levels.” Ex. 2-52 at 3–4 (Department Export Authorization EA-365-C (Oct. 21, 2025)). To address this prong, the Department “examines whether existing electric supply is available via market mechanisms, and whether potential reliability issues linked to supply problems are mitigated by reliability enforcement mechanisms.” *Id.* at 4. The Department interprets the “coordination” prong of Section 202(e) “primarily as an issue of the operational reliability of the domestic electric transmission system” and, “[a]ccordingly, the export must not compromise transmission system security and reliability.” *Id.*

The Department’s authorizations to export power from MISO (and other areas) to Canada demonstrate the false basis of the Orders’ emergency determination. For instance, in a recent export authorization, the Department explains why allowing exports to Canada will not impair the sufficiency of domestic electric supply. “From an economic perspective,” which the Department explains regards “the supply available to wholesale market participants,” the Department “finds that the wholesale energy markets are sufficiently robust to make supplies available to exporters and other market participants serving United States regions along the Canadian and Mexican borders.” *Id.* at 4. And from a reliability perspective, through which the Department “focuses on preventing problems that could result from inadequate supplies,” the Department says nothing about possible inadequate supplies. *Id.* Instead, the Department recounts the multi-layered and “comprehensive” reliability processes that “ensure[] that bulk-power system owners, operators, and users have a strong incentive both to maintain system resources and to prevent reliability problems that could result from movement of electric supplies through export.” *Id.* at 5–6; *see also id.* at 7–8 (explaining further some authorities of balancing authorities and reliability coordinators).

The Orders do not reconcile the Orders’ emergency determination with the export authorizations’ findings that markets in the area are sufficiently robust to make supplies available, and that multi-layered and comprehensive reliability processes incentivize maintenance of system resources. The Orders are thus unreasoned and not based on substantial evidence.

Notably, while the Orders attempt without justification to sow doubt about resource adequacy in non-summer seasons generally, they provide no evidence indicating any actual risk of inadequate supply in the Spring 2026 season, which is the time period mainly at issue in the Orders. This is a staggering abdication of the Department’s obligation to provide sound evidentiary backing for its emergency declarations and further confirms that there is no remotely sound reason to be concerned about resource adequacy shortfalls in Spring 2026.

Finally, as explained above in Section IV and in the Konidena April Declaration, Ex. 173 at 8, the Department erroneously claims that MISO’s conservative operations during Winter Storm Fern “demonstrate” MISO’s resource adequacy concerns. It is improper to draw broad conclusions about the stability of the grid from late winter to mid-spring based on a single event in January (which ignores the significant variation in conditions that grid operators face in different seasons). Moreover, MISO’s operation of the grid during Winter Storm Fern maintained full electric service to all customers using exactly the resources (power imports, demand-side resources, and maximum generation alerts) that Public Interest Organizations have explained are designed for this purpose and intended to be used in such circumstances. MISO maintained grid reliability during the entirety of Winter Storm Fern even in the face of unexpected software and mechanical issues that interfered with its operations, and its standardized responses to the event served their purpose. The capacity of the generators subject to the Department’s 202(c) orders in MISO—Schahfer, Culley 2, and Campbell—were not needed to provide capacity even during the highest-load hours of Winter Storm Fern. See Ex. 173 at 8 (Konidena April Declaration).

B. The Orders Are Not Based on Reasoned Decision-Making and Substantial Evidence in Imposing Requirements to Best Meet the Claimed Emergency and Serve the Public Interest.

The Orders determine that additional dispatch of Schahfer and Culley 2 are necessary to best meet the purported emergency and serve the public interest. But the Orders provide no rational basis for that determination. The Orders do not address the limitations of either the Schahfer or Culley 2 plant, or explain how, in light of those limitations the Plants could even meet the claimed emergency. In fact, both Plants are unlikely to be able to do so. The Orders do not examine the expense

of running any of the units or the associated environmental damage, factors which cause additional dispatch of the plant to harm, rather than serve, the public interest. And the Orders do not address readily available and obvious alternatives which, in point of fact, would better meet the claimed emergency. The Orders also fail to consider how they are causing economic damage by, *inter alia*, crowding out otherwise competitive resources, disrupting planning, and creating policy-driven uncertainty. See Ex. 137 at PDF pp. 2–3 (R Street Institute Commentary: *DOE “Zombies” Are Eating Competitive Power Markets*). Consequently, and for the reasons further discussed in the following subsections, the Order is without support in the record, unreasoned, and unlawful. *Allentown Mack*, 522 U.S. at 374; *State Farm*, 463 U.S. at 42–43, 51; *Burlington Truck Lines*, 371 U.S. at 168; *Butte Cnty.*, 613 F.3d at 194.

1. *Legal Framework: Section 202(c)(1) Authorizes the Department to Require Only Generation that Best Meets the Emergency and Serves the Public Interest.*

Section 202(c)(1) authorizes the Department to impose only those requirements that (i) “best” (ii) “meet the emergency and” (iii) “serve the public interest.” 16 U.S.C. § 824a(c)(1).

The term “best” demands a comparative judgment that there are no better alternatives. The word “best” is inherently a comparative term and means “that which is ‘most advantageous.’” *Entergy Corp. v. Riverkeeper, Inc.*, 556 U.S. 208, 218 (2009) (*quoting* Webster’s New International Dictionary 258 (2d ed.1953)); *cf. Sierra Club v. Env’t. Prot. Agency*, 353 F.3d 976, 980, 983–84 (D.C. Cir. 2004) (explaining that statutory “best available control technology” requirement demands sources in a category clean up emissions to the level that peers have shown can be achieved). Consequently, the Department must, at minimum, consider alternatives and evaluate whether and to what extent a given alternative addresses the emergency and serves the public interest, including deficiencies associated with the alternative.¹⁷

The Department’s obligation to exercise reasoned decision-making further requires consideration of alternatives. The Department need not consider every conceivable alternative, but it must consider alternatives within the ambit of the regulatory context as well as alternatives which are significant and viable or

¹⁷ To be sure, the nature and extent to which the Department must consider alternatives depends on the emergency. An emergency that truly requires the Department to act within hours, for instance, permits a more abbreviated consideration than an emergency for which the Department has days to decide.

obvious. *See Dep't of Homeland Sec. v. Regents of the Univ. of Calif.*, 591 U.S. 1, 30 (2020); *Motor Vehicle Manufs. Ass'n of the U.S. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 51 (1983); *Nat'l Shooting Sports Found., Inc. v. Jones*, 716 F.3d 200, 215 (D.C. Cir. 2013). Intervenors and the public may also introduce information that requires the Department to evaluate alternatives and reconsider its decision to impose or maintain a requirement. *See, e.g., Chamber of Com. of the U.S. v. Secs. & Exch. Comm'n*, 412 F.3d 133, 144 (D.C. Cir. 2005) (evaluating agency failure to consider alternative raised by dissenting Commissioners and introduced by commenters); *cf.* 10 C.F.R. § 205.370 (stating ability to cancel, modify, or otherwise change an order).

The Department's regulations and practice identify relevant alternatives for its consideration. The regulations specify information the Department shall consider in deciding to issue an order under Section 202(c), and require an applicant for a 202(c) order to provide the information. 10 C.F.R. § 205.373. The specified information includes "conservation or load reduction actions," "efforts . . . to obtain additional power through voluntary means," and "available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions." *Id.* §§ 205.373(f)–(h); Ex. 9 at 4 (DOE Order No. 202-22-4).

The Department may then choose only the best alternative. The best alternative is the one that is most advantageous for meeting the stated emergency and serving the public interest.

The statutory command to take only measures that serve the public interest, including with respect to environmental considerations, further constrains the Department's authority. The public interest element demands that the Department advance, or at least consider, the various policies of the Federal Power Act. *Cf. Wabash Valley Power Ass'n*, 268 F.3d at 1115 (interpreting the "consistent with the public interest" standard in Section 203 of the Federal Power Act); *see Gulf States Utils. Co. v. Fed. Power Comm'n*, 411 U.S. 747, 759 (1973); *California v. Fed. Power Comm'n*, 369 U.S. 482, 484–86, 488 (1962). Primary policies of the Federal Power Act include protecting consumers against excessive prices; maintaining competition to the maximum extent possible consistent with the public interest; and encouraging the orderly development of plentiful supplies of electricity at reasonable prices. *NAACP v. Fed. Power Comm'n*, 425 U.S. 662, 670 (1976) (orderly development); *Otter Tail Power Co. v. United States*, 410 U.S. 366, 374 (1973) (maintaining competition); *Pa. Water & Power Co. v. Fed. Power Comm'n*, 343 U.S. 414, 418 (1952) (excessive prices). And because Section 202(c) expressly protects environmental considerations, these are part of the public interest element too. *See*

NAACP, 425 U.S. at 669 (“[T]he words ‘public interest’ . . . take meaning from the purposes of the regulatory legislation.”).

2. The Orders do not address the generators’ unreliability or explain how, in light of that unreliability, the generators could meet the claimed emergency.

The Orders are unreasoned and not based on substantial evidence in requiring the Plants’ availability and operation while failing to address the Plants’ unreliability.

Schahfer is old and creaky, with significant reliability issues, as discussed above in section IV.C.3.i. In anticipation of its retirement, NIPSCO has deferred maintenance on Units 17 and 18, further exacerbating the reliability of the plant. These reliability issues raise significant doubt that Schahfer is capable of reliable operation such that it could meet the claimed emergency. In fact, forcing the unreliable Schahfer to continue operating actually threatens grid reliability.

Both Schahfer Unit 17 and Unit 18 have seen repeated and significant unforced outages in recent months, reflecting the units’ deteriorating state. In 2024, NIPSCO’s equivalent forced outage rate (“EFOR”), which represents the percentage of time (in hours) a unit was unable to generate power for reasons other than planned maintenance, was 18.8% and 13.2% for Schahfer Units 17 and 18 respectively. Ex. 4 at 5 (Powers January Declaration). These rates are substantially worse than the national average for coal-fired units of 12 percent. *Id.*; see Ex. 40 at 59 (NERC 2024 Reliability Report). This is driven in part by the fact that the units are so uneconomical. As NIPSCO explains,

“NIPSCO’s coal EFOR has been significantly affected by changing power markets, which has changed the economical dispatch for coal. Infrequent operation for years, which imposes high thermal stresses on a unit, leading to an increase in forced and maintenance outage hours, followed by an increase in the demand for operating hours later in the year, exacerbates the issues.”

Ex. 13 at 21 (NIPSCO Performance Metric Collaborative Update).

NIPSCO’s coal units are both dilapidated and expensive enough that their net capacity factor—that is, the percentage of a unit’s nameplate capacity that it actually produces considering both outages and how often it is scheduled to dispatch—was at 25% for 2024. *Id.* at 22.

The units’ outage rate in 2025 has been similarly dismal. Unit 18 has spent more than 5,000 hours, over 212 days, in unforced outages during the first three quarters

of 2025. *See* Ex. 4 at 6 (Powers January Declaration) (citing Ex. 14 at attachment 4-A (Saffran Q1 2025 Outage Testimony); Ex. 15 at attachment 4-A (Saffran Q2 2025 Outage Testimony); Ex. 16 at attachment 4-A, p. 2 (Saffran Q3 2025 Outage Testimony)). Unit 18's L-1 turbine blade separated from the root and fell into the condenser in February, causing an unforced outage that left the unit offline until late June. *See* Ex. 15 at attachment 4-A, p. 2 (Saffran Q2 2025 Outage Testimony). In early July, the unit experienced another outage when one of the L-0 blades on the governor end fell off one third of the way down from the tip. Ex. 16 at attachment 4-A (Saffran Q3 2025 Outage Testimony). The same November 20, 2025 filing from a NIPSCO official reports "significant damage to the upper portion of the condenser tubes on the governor end." *Id.* Unit 18 is quite literally falling apart, and treating the unit as a critical energy asset needed to maintain reliability is facially absurd. Unit 17, while perhaps a bit less dramatically enfeebled, is also falling apart. Unit 17 spent 1,118 hours in unforced outages in 2025. *See* Ex. 4 at 6 (Powers January Declaration) (citing Ex. 14 at attachment 4-A (Saffran Q1 2025 Outage Testimony); Ex. 15 at attachment 4-A (Saffran Q2 2025 Outage Testimony); Ex. 16 at attachment 4-A, p. 2 (Saffran Q3 2025 Outage Testimony)). On September 6, the unit experienced a 201 hour unforced outage to "replace bad tubes and repair previously installed dutchmen." Ex. 16 at attachment 4-A, p. 2 (Saffran Q3 2025 Outage Testimony). In addition to the 1,044 hours cited in the Powers January Declaration, Unit 17 went on forced outage for 74 hours on November 9 due to a water level alarm. Ex. 174 at 7 (Saffran Q4 2025 Outage Testimony).

Repair of Unit 18 to get it to a working state looks impossible within the timeframe of the March Schahfer Order. As NIPSCO's president explained late last year before the Indiana Commission:

"Unit 18 is in a forced outage; that one will take more time and effort to ultimately get it to where it needs to be, and at some point, if we do get a 202(c) [order], and it continues, we'll likely have to do some work on [Unit] 17 as well. . . . We've taken some steps to be prepared—long lead time equipment, in particular, that ultimately would have to be ordered for us to come in. Frankly, that unit needs to be rebuilt. . . . We're taking some steps to be able to do that, but it will take time; it can take six months or longer for us to ultimately be able to get that unit back to where it would need to be to operate for an extended period of time. It's just the reality of that unit being close to retirement. We're not completely unprepared, but it will take time to get that long lead time items in to be able to make the repairs necessary."

Ex. 53 (IURC 2025 Winter Reliability Forum (December 2, 2025), video recording available at <https://www.youtube.com/watch?v=bCzALF4V45M>, excerpt beginning at 51:35 timestamp). VP Bryan McCaul explained that, in anticipation of a 202(c) order from the Department, NIPSCO has “had a lot of negotiations with the [original equipment manufacturer], and trying to pull in future possible deliveries on those [replacement turbine] blades, and also looking at the [high pressure and intermediate pressure] turbines. . . . There’s a lot of contract stuff happening trying to make sure we are positioned to not have what was originally an 18 month lead time on those blades, maybe be more like March or May.” *Id.* at 58:44. More recently, at a March 24, 2026 conference at the Indiana Commission, a NIPSCO representative stated that Schahfer Unit 18 remained out of service and did not offer a specific timeline for bringing it back online and stated only that NIPSCO was “continuing to evaluate” Unit 18’s outage. Ex. 180 (IURC March 2026 Affordability Forum (Mar. 24, 2026), video recording available at <https://www.youtube.com/watch?v=uXEwNQdi3r0>, excerpt beginning at 3:45:19 timestamp). Even in NIPSCO’s most optimistic case, Schahfer Unit 18 may not be able to operate through much of the 90-day period for the March Schahfer Order.

At a minimum, the Orders are inconsistent with the long-term and orderly planning processes that utilities undertake to shore up reliable operations; at worst, they set MISO up to rely on generators that will fail unexpectedly.

Even if Schahfer were not falling apart, there is significant reason to think that Units 17 and 18 could not act as reliability resources during the pendency of the December and March Schahfer Orders. NIPSCO has depleted Schahfer’s coal stocks as it prepared for retirement. *See* Ex. 18 at 23 & 23 n.14 (Wagner November Testimony) (stating that Schahfer had 16 days coal inventory supply at the end of September 2025, whereas the target is a supply for 40 days with a plus or minus 10 day window of variability). And at the end of December 2025, which was the long-planned retirement date for the Schahfer coal units, coal inventory there was down to 4 days’ worth. Ex. 175 at 24 (Wagner February Testimony). And it seems unlikely that NIPSCO would be able to easily return to having reasonable coal stockpiles. As NIPSCO’s fuel manager explained to the Indiana Commission, “NIPSCO’s [rail] fleet size at the end of [September 2025] can provide 76% of NIPSCO’s maximum coal unit demand and at average railroad cycle times.” *Id.* at 23. NIPSCO is hampered in its ability to supply Schahfer with coal, and it has limited coal reserves on-site that it can draw from. Nor could NIPSCO easily obtain more train capacity to provide Schahfer additional coal. The same NIPSCO expert explained:

[T]he availability of coal gondolas is extremely limited and relying on that market to obtain railcars for short-term needs can adversely

impact coal supply reliability and is not prudent. In addition, the timing of lease terms can preclude fleet size changes as leasing decisions are made on a forward-looking basis. . . . [I]t can take several months to bring cars into the fleet, and it is an even longer process when returning cars. In addition, moving rail cars in and out of service is a costly process. Therefore, the forward-looking nature of lease agreements and the time and costs required to place cars in and out of service make it difficult to make short-term changes to the size of the fleet and it is not prudent, practical, nor economic to dynamically change the fleet size when coal demand deviates from the forecast.

Id. at 21–22 (footnote omitted).

Moreover, even if it had the train cars to get the coal to the plant, NIPSCO sees risk in its ability to source the coal. As NIPSCO explained:

[V]ariable coal demand impacts supply chain efficiency and can lead to unpredictable coal supplier and railroad performance. . . . Given the uncertainty in the energy markets due to delayed coal generation retirements, projected increases in electricity demand due to the emergence of data centers, crypto mining, and other load growth drivers, there could be volatility in all energy commodity prices that could impact supply. . . . [I]f coal demand increases, utilities may struggle to schedule deliveries as railroads and coal producers have rationalized assets, labor, and production, and it may take time for production and shipments to rise to meet any rapid increase in demand.

Id. at 15–17, 23.

These limitations severely undercut any reliability role Schahfer could reasonably play and are entirely ignored in the Department’s March Schahfer Order.

Culley 2 is likewise an unreliable and creaky generator. Culley 2 had an EFOR in 2024 of 32.4% and a net capacity factor of 31.8%. Ex. 22 at 24 (CenterPoint 2024 Performance Report); Ex. 4 at 8 (Powers January Declaration). Like the Schahfer units, the Culley EFOR rates are substantially worse than the national average for coal-fired units of 12 percent. Ex. 4 at 8 (Powers January Declaration); *see also* Ex. 40 at 59 (NERC 2024 Reliability Report). Culley 2 has been experiencing boiler tube leaks that have been causing outages and forcing the unit offline. Ex. 22 at 24 (CenterPoint 2024 Performance Report). And the maintenance issues are likely to get worse, not better. CenterPoint Indiana has anticipated the retirement of Culley

2 and therefore not invested in major maintenance needed to keep the plant operating smoothly, as CenterPoint Indiana’s vice president of power operations relayed to the Indiana Commission. “In 2025, the plant will be years past due for a turbine and generator overhaul and will require major boiler work and other capital investments to maintain safe and reliable operation.” Ex. 23 at 6 (Wayne Games 2021 Testimony). CenterPoint Indiana reported that its “Culley 2 maintenance expenditure declined about 20% from 2022 to 2023 in [FERC Uniform System of A]ccount[s] 512 (Maintenance of Boiler Plant).” Ex. 4 at 9 (Powers January Declaration) (citing Ex. 152 at PDF pp. 8, 20 (CenterPoint Rate Case Discovery Responses)). “Increased maintenance spending is necessary to minimize the effect of equipment degradation with age and changing operating regimes. Plants such as F.B. Culley that have likely underspent on capital investment and O&M are at greater risk of future forced outages.” Ex. 4 at 9 (Powers January Decl.). These entirely foreseeable maintenance issues hampered Culley’s operation during the period of the December Culley Order. In fact, CenterPoint Indiana confirmed that during the first 48 days of the December Culley Order, the plant experienced maintenance issues that prevented regular operation of the plant nearly 90% of the time. Ex. 169 at 2 (CenterPoint Letter to USDOE) (describing operational issues during 43 of the first 48 days). It is unlikely that the plant can stay online and operational to address the purported emergency identified by the March Culley Order.

The Orders fail to come to grips with the dangers to grid reliability that they create. Unreliable coal plants like Culley 2 and Schahfer are particularly likely to cause grid disturbances. .

“Cold snaps, heat waves, and storms have all exposed coal’s fragility during grid stress events. Reliability is not just about being dispatchable, it’s about delivering performance under stress. Coal plants struggle to do that consistently. For coal plants to truly meet the constant demands of data centers, they would need to run at high capacity factors and avoid major outages, all of which fly in the face of current performance trends. If a large coal plant trips offline while supporting a cluster of data centers, the sudden loss of supply could lead to cascading failures across the grid. This is because generation must equal load at all times, datacenter or no datacenter. As a result, relying on coal plants to support these high-density digital loads doesn’t enhance reliability, it endangers it. And it’s not a matter of *if* the coal plant will fail, but *when*.”

Ex. 118 at PDF pp. 2–3 (RMI Analysis of Coal Plants’ Threats to Reliability).

The Department avers that it is concerned with reliability, *see* Ex. 1 at 4 (December Schahfer Order); Ex. 2 at 5 (December Culley Order); Ex. 158 at 8–9 (March Schahfer Order); Ex. 159 at 8–9 (March Culley Order), yet puts forward no analysis to address the likelihood that its Orders might actually create the (otherwise unproven) problem they are supposedly trying to address. The Department mandates generation from old plants which, in anticipation of their retirements, deferred significant maintenance needs, while stylizing the generators as needed for reliability, risking sudden break-downs and grid stability concerns. This ostrich-like approach to record evidence and public information is not reasoned decision-making. *Butte Cnty.*, 613 F.3d at 194; *cf. Ky. Mun. Energy Agency v. FERC*, 45 F.4th 162, 177 (D.C. Cir. 2022) (rejecting “ostrich-like approach” to agency decision-making).

3. The Orders Do Not Address the Plants’ Continued Demonstration of Their Technical Inability to Meet the Claimed Emergency.

Separately, the Orders provide no reasoned basis to conclude that Schahfer and Culley 2, even if fully maintained and operational, could meet the claimed emergency, let alone that these Plants are the best way to do so, given the technical specifications and operational limits of the Plants.

Schahfer and Culley 2 are not designed to turn on quickly in response to extreme demand, nor are they capable of ramping their output up and down quickly. The Orders point to projections of demand growth, including from “data centers driving artificial intelligence (AI) innovation.” Ex. 1 at 4 (December Schahfer Order) (internal quotation marks omitted); Ex. 2 at 4 (December Culley Order) (same) Ex. 158 at 7 (March Schahfer Order); Ex. 159 at 7 (March Culley Order). Even assuming *arguendo* the Department has authority under Section 202(c) to address that claimed circumstance (it does not), coal plants’ “always-on nature” and “rigidity” are “a poor match for the dynamic and often unpredictable nature of data center demand.” Ex. 118 at PDF p. 3 (RMI Analysis of Coal Plants’ Threats to Reliability); *see also* Ex. 129 at 3 (Energy Innovation Report) (explaining that data center loads “are not 24/7 blocks. Instead, they are choppy, with swings of hundreds of megawatts over short intervals, undermining assumptions of steady baseload behavior and potentially affecting the stability of the grid if safeguards are not put in place.”). “[L]arge, voltage-sensitive loads like data centers require flexible, responsive grid solutions, not slow-ramping generators that can take 12 or more hours to come online.” Ex. 118 at PDF p. 3 (RMI Analysis of Coal Plants’ Threats to Reliability) (relying on NERC). Fast-ramping generators are also needed to respond to extreme emergency demand increases in cases when an emergency is declared only a few hours before the demand must be met. Ex. 4 at 10 (Powers January Declaration).

Schahfer has slow ramp and startup times, as noted above in section IV.C.3.i.b. The two coal generating units have start-up targets of 22 hours after a 1-hour notice and ramp rates of 3 MWs per minute. Ex. 19 at 6 (NIPSCO CPCN Discovery Responses). NIPSCO has recognized that its coal units at Schahfer are ill suited to meet its customers' needs because of their slow ramp and start times. NIPSCO sought and received permission to decommission and reuse the interconnection rights associated with Units 17 and 18 for new gas-fired generators at the same site that would not face these problems. See Ex. 20 at 18 (IURC Schahfer Gas Plant Order) (describing NIPSCO's finding that it needed generation with faster ramp rates and start up times); *id.* at 14, 17 (discussing how the proposed CTs would use the interconnection rights associated with retiring units 17 and 18); *id.* at 42 (the Indiana Commission approving NIPSCO's plan to build the CTs in question). The new CT units, in contrast to Units 17 and 18, can start up in as few as 11 minutes and have a ramp rate of 140 MWs per minute, making them significantly more responsive than Units 17 and 18 to swinging demand. Ex. 19 at 6 (NIPSCO CPCN Discovery Responses). The Department's order forcing Schahfer to stay online risks delaying the in-service date for these new responsive units, because the new CT units were designed to come online using the interconnection rights of the retiring units 17 and 18. Considering how the new CT units may now have delayed in-service dates, the December and March Schahfer Orders risk degraded reliability for NIPSCO and MISO customers.

CenterPoint Indiana has reached similar conclusions with regard to Culley 2. CenterPoint Indiana created two proposed generation portfolios for its 2025 integrated resource plan: a "preferred portfolio" which offered among the lowest cost and most flexible operating futures for CenterPoint Indiana in a range of possible future scenarios, and an "alternate preferred portfolio," which offers lowest cost generation solutions assuming significant large load growth. Ex. 21 at 10–11, 165–68, 185–86 (CenterPoint Indiana 2025 IRP). CenterPoint Indiana's analysis found that in the high data center load growth scenario, Culley 2 should be retired and have its interconnection rights used for a battery storage installation at the site to support system capacity and provide additional ramping capability. See *id.* at 10, 185–186; see also Ex. 2 at 4 (December Culley Order) (asserting emergency conditions because of data center demand). Even without the large load assumption, use of the Culley 2 interconnection for a battery storage installation is in the preferred portfolio. Ex. 71 at 139, 165–166 (CenterPoint Indiana 2025 IRP).

The Plants are ill-suited to meet the highly variable and rapidly changing load of data centers, even compared to other coal units. The average coal plant takes 12 hours to reach maximum capacity from a cold start. Ex. 55 at 26 (IEA Flexibility Report); Ex. 118 at PDF p. 3 (RMI Analysis of Coal Plants' Threats to Reliability). By comparison, utility-scale battery storage can dispatch from a cold start to full

power in a matter of seconds. Ex. 4 at 10 (Powers January Decl.). Schahfer and Culley 2, with their long startup times, are ill-suited to serve as peaking plants that respond to extreme peak demand on short notice. Ex. 4 at 10–12 (Powers January Decl.).

In short, the Orders fail to examine the inherent mismatch between the problem they diagnose and the mandates they impose. Schahfer and Culley 2 are both falling apart, and unsuited to meet the rapid ramping needs associated with the data center load growth the Orders identify as driving the purported emergency.

4. The Orders Do Not Address or Reflect Consideration of Alternatives.

Other alternatives are available to the Department that better meet the claimed emergency and serve the public interest. MISO has access to robust transmission connectivity between itself and neighboring regions to support the stability of its grid. *See, e.g.*, Ex. 35 at 2 (Patton MISO Comments) (“[I]t is important to recognize that, unlike some other RTOs, MISO has tremendous import capability that is routinely utilized during tight conditions to supplement its internal resources.”). During most of the period of the Orders, MISO Zone 6 can import more than 7.5 GW. Ex. 3 at 8 (EFG Report); Ex. 37 at 12 (MISO 2025–2026 CIL/CEL Final Results); *see generally* Ex. 65 at 52–53 (DOE Transmission Planning Study) (documenting interregional variability in electricity demand); Ex. 66 at 22–35 (NERC 2024 Interregional Transfer Capability Study, Part 1) (describing transfer capabilities between MISO and other regions). For the portion of the Orders’ period falling in Summer 2026, MISO Zone 6 can import 6,440 MW. Ex. 176 at 4 (MISO 2026–2027 CIL/CEL Results). The Department has long recognized that power pools and utility coordination “are a basic element in resolving electric energy shortages.” *Emergency Interconnection of Elec. Facilities and the Transfer of Elec. to Alleviate an Emergency Shortage of Elec. Power*, 46 Fed. Reg. 39,984, 39,985–86 (Aug. 6, 1981). And recent history bears out the important role of transmission connectivity along with imports and exports. *See, e.g.*, Ex. 43 at 64 (Winter Storm Elliott System Operations Inquiry) (“Despite tightening conditions on the MISO system as the morning progressed, MISO maintained steadily increasing exports to TVA throughout the day.”); Ex. 44 at 43, 83–84 (PJM Elliott Report) (describing PJM exports of between 8 and 11 GW to TVA, and exports to MISO and other regions); Ex. 36 at 6 (MISO Elliott Max. Gen. Event Overview) (“MISO consistently exported power to southern neighbors with a maximum value of nearly 5 GW[.]”); *see also* Ex. 7 at 1 (DOE Order No. 202-02-1) (providing for usage of interregional transmission).

The Orders fail to consider the alternative of imports and transmission connectivity to meet the claimed emergency. The Orders include no reasonable basis to question the availability of resources from neighboring regions, nor why the

Orders provide a better means of ensuring resource sufficiency than addressing those barriers directly through its power to require “interchange” and “transmission” of electric energy from those neighboring regions. 16 U.S.C. § 824a(c)(1); *see* 10 C.F.R. §§ 205.373(f) & 205.375 (providing for consideration of available resources, including power transfers). The Orders’ failure to consider imports and interregional transmission connectivity is unreasoned, and the Orders are not based on substantial evidence.¹⁸

The Orders also fail to consider limiting exports to Canada from MISO as another alternative to meet the claimed emergency. The Department has authorized many entities to export energy from MISO, including new authorizations in the last year. *See* Department Export Authorizations Library, <https://www.energy.gov/oe/export-authorization-library> (last visited Apr. 19, 2026); Ex. 2-52 at 11 (Department Export Authorization EA-365-C (Oct. 21, 2025)). In addition to the Department’s Section 202(c) authority, Section 202(e) of the Federal Power Act authorizes the Department to supplement or modify its export orders if necessary or appropriate. 16 U.S.C. § 824a(e). The Department could modify its export authorization to halt or limit exports from MISO if the power is needed to avert a true emergency. However, nothing in the Orders points to this as a considered alternative.

C. The Orders Exceed Other Limits on the Department’s Authority.

1. The Department Lacks Jurisdiction to Impose the Availability Requirements.

In directing MISO, NIPSCO, and CenterPoint Indiana to take “all measures” to ensure that Schahfer and Culley 2 are “available to operate,” Exs. 158 at 8 (March Schahfer Order); 159 at 8 (March Culley Order), the Department exceeds its authority under Section 202(c) of the Federal Power Act and impermissibly intrudes on the authority over generating facilities that Section 201(b) of the statute reserves to the states, 16 U.S.C. §§ 824(b)(1), 824a(c)(1). The sweeping language in the Department’s Orders would encompass physical and all other changes necessary to revive a decrepit generating plant undergoing closure pursuant to a state-approved

¹⁸ The Department must also incorporate demand response and other alternatives in determining whether an emergency exists, and as a condition precedent to calling for generation by a polluting resource like Schahfer or Culley 2, a requirement consistent with Departmental practice. *See* 16 U.S.C. §§ 824a(c)(1)–(2); 10 C.F.R. § 205.375; e.g., Ex. 39 at 4–5 (DOE Order No. 202-22-2); Ex. 45 at 2–3 (DOE Order No. 202-21-1); Ex. 17 at 3 (DOE Order No. 202-20-2). MISO has access to demand response and authority over generator outages. *See* Ex. 70 at ¶¶ 20–23 (Konidena September Decl.)

retirement process. The Federal Power Act's language, structure, legislative history, and interpretation by the courts all confirm that the Department's Orders are unlawful.

The structure and language of the Federal Power Act reflect Congress's deliberate choices to preserve the states' traditional authority over generating facilities and to circumscribe the Department's emergency authority in light of the states' role. The first sentence of the Federal Power Act declares that federal regulation extends "only to those matters which are not subject to regulation by the States." *Id.* § 824(a). Section 201(b)(1) states that, except as otherwise "specifically" provided, federal jurisdiction does not attach to "facilities used for the generation of electric energy." *Id.* § 824(b)(1). The courts have held that Section 201(b)(1) reserves to the states authority over electric generating facilities, *see, e.g., Hughes v. Talen Energy Mktg., LLC*, 578 U.S. 150, 155 (2016), including the authority to order their closure, *Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481 (D.C. Cir. 2009) (explaining that under Section 201(b), states retain the right "to require the retirement of existing generators" or to take any other action in their "role as regulators of generation facilities"). Congress also recognized the states' exclusive authority over generating facilities in Section 202(b), which provides that FERC's interconnection authority does not include the power to "compel the enlargement of generating facilities for such purposes." 16 U.S.C. § 824a(b).

There is a clear distinction between authority to regulate generation facilities and the Department's authority under Section 202(c) to require generation of electric energy. Electric energy is an electromagnetic wave, and its "generation, delivery, interchange, and transmission" is the creation and propagation of that wave. *See Brief Amicus Curiae of Electrical Engineers, Energy Economists and Physicists in Support of Respondents at 2, New York v. FERC*, 535 U.S. 1 (2002); *see also* Edison Electric Institute Glossary of Electric Utility Terms (1991 ed.) (defining electric generation as "the act or process of transforming other forms of energy into electric energy"). Section 202(c)(1), like the rest of the Federal Power Act, is written "in the technical language of the electric art" and federal jurisdiction generally "follow[s] the flow of electric energy, an engineering and scientific, rather than a legalistic or governmental test." *Conn. Light & Power v. Fed. Power Comm'n*, 324 U.S. 515, 529 (1945); *see also Fed. Power Comm'n v. Fla. Power & Light Co.*, 404 U.S. 453, 454, 467 (1972).

The scope of the Department's emergency power under Section 202(c) is bounded both by the provision's specific language and Congress's clear intention and repeated direction in the Federal Power Act to respect the states' authority over generating facilities. When an actual emergency exists, Section 202(c)(1) authorizes the Department to order only two specific things: (1) "temporary connections of

facilities” and (2) “generation, delivery, interchange, or transmission of electric energy.” *Id.* § 824a(c)(1). The only reference to “facilities” in the authorizing provision of Section 202(c)(1) appears in the clause relating to temporary connections, not in the clause pertaining to “generation” of electric energy. And that clause only authorizes connections “of” facilities; it does not provide authority to regulate the facilities. The differences in Congress’s word choice in these clauses—referencing “facilities” in one authorizing provision but not the other—must be given effect. *See, e.g., Gallardo v. Marsteller*, 596 U.S. 420, 430 (2022); *Gomez-Perez v. Potter*, 553 U.S. 474, 486 (2008).

Given Congress’s use of the term “generating facilities” elsewhere in the statute, if it had intended to give the Department authority over generating facilities in Section 202(c)(1), it would have done so explicitly. Instead, the provision conspicuously excludes authority to manage the physical characteristics of power plants. Congress purposely limited and particularized the Department’s emergency powers, carefully avoiding intrusion on the states’ authority over generating facilities recognized in Section 201(b)(1). *See* S. Rep. No. 74-621, at 19 (explaining that the emergency powers in Section 202(c)(1) “which were indefinite in the original bill have been spelled out with particularity”); *compare* S. 1725, Cong. Tit. II § 203(a) (providing in original, unenacted bill that control of the production and transmission of electric energy “except in time of war or other emergency declared to exist by proclamation of the President, shall, as far as practicable, be by voluntary coordination”), *with* 16 U.S.C. § 824a(c)(1) (providing particularized, specific authorities and circumstances in which the authorities may be exercised).

In certain circumstances, the Department may require generation of electric power, and a utility may properly take steps at the facility to produce the power. It is commonplace in the electric sector for the federal regulator properly acting within its authority to cause effects in a state regulator’s jurisdictional sphere, and vice versa. *See Elec. Power Supply Ass’n*, 577 U.S. at 281. But the federal regulator may neither directly regulate generation facilities nor impose requirements aimed at the facilities, even if nominally regulating within its sphere. *See id.* at 281–82; *see also Hughes*, 578 U.S. at 164–65. Such encroachment is impermissible, be it in a real emergency or in a wrongly claimed one. *See Conn. Light & Power*, 324 U.S. at 530 (“Congress is acutely aware of the existence and vitality of these state governments. It sometimes is moved to respect state rights and local institutions even when some degree of efficiency of a federal plan is thereby sacrificed.”). Thus, the Department may not require generation that necessitates the utility taking steps under state authority, such as building a new generating unit or refurbishing a broken one.

The Federal Power Act does not give the Department sweeping authority to order “all measures” needed to make a generation facility “available to operate.”

Ex. 158 at 8 (March Schahfer Order); Ex. 159 at 8 (March Culley Order); *see* 16 U.S.C. § 824a(c). Nowhere does the statute empower the Department to order “all” steps that may be needed to ensure the availability of Culley 2 and Schahfer, which could include repairs or modifications to physical facilities and other measures going far beyond electric power generation. Because generating units at both Plants are at the end of their useful lives, with years of forgone maintenance and capital expenditures, rendering the units capable of meeting a short-term supply shortfall could essentially require rebuilding significant parts of the Plants. On their face, the Department’s Orders are *ultra vires*. The Orders also contravene the Federal Power Act’s repeated direction to respect the states’ authority over generating facilities, which includes the authority reserved to Indiana to ensure responsible closures of both generators. The Orders therefore are unlawful and should be withdrawn.¹⁹

2. The Department Lacks Jurisdiction to Disallow Treatment of Schahfer or Culley 2 as a Capacity Resource.

The Orders state that “[b]ecause this order is predicated on the shortage of facilities for generation of electric energy and other causes,” Schahfer and Culley “shall not be considered capacity resources.” Ex. 158 at 9 (March Schahfer Order); *see also* 159 at 9 (March Culley Order) (directing that Culley 2 shall not be considered a capacity resource). This provision serves only to increase costs to customers, who will be required to procure duplicative capacity as a result. It is also illegal. Section 202(c) authorizes the Commission to “require by order . . . temporary connections of facilities and . . . generation, delivery, interchange, or transmission of electric energy,” and then shields facilities that operate pursuant to a Section 202(c) order from liability for unavoidable violations of federal, state, or local environmental laws or regulations. 16 U.S.C. §§ 824a(c)(1), (3). Nowhere does the Federal Power Act suggest that the Department may predetermine or override the reasoned decisions of FERC in its determination of whether just and reasonable wholesale rates require an operating resource to be considered a capacity resource. Indeed, the very nature of 202(c) orders, which are limited to emergencies involving extant resource shortfalls (in which, by definition, there are no alternative capacity resources that might be displaced by the ordered generation) suggests that capacity resource treatment is well outside the Department’s 202(c) authority.

¹⁹ A utility that takes steps subject to state authority cannot point to a Section 202(c) order as the basis for a right to recover associated costs. *See* 16 U.S.C. § 824a(c)(1) (providing for compensation or reimbursement to be paid based on just and reasonable terms for carrying out an authorized order).

In addition, the Orders fail to tie this direction to the purported emergency underlying the Orders. The Orders also fail to articulate any rational connection between this direction and the Department’s limited authority to “order such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest.” 16 U.S.C. § 824a(c)(1).

The explanation the Orders offer for this override, essentially that Schahfer and Culley 2 cannot be capacity resources because the orders do not deem them capacity resources, is clearly circular. As a result, the true reasoning behind this provision remains unclear—but its clear effect is to prevent MISO from considering the continued existence of Schahfer or Culley 2 as it works to ensure resource adequacy across its footprint. MISO’s tariff defines a “capacity resource” as any of several types of resources “that are available to meet demand,” and its definition of “Planning Resource” makes clear that generators like Schahfer and Culley 2 must be a Capacity Resource in order to satisfy a region’s Reserve Margin Requirement. MISO Tariff Sec. 1.C, 1.P (Definitions). The Tariff also establishes clear procedures for calculating capacity contribution from all resources. *Id.* at Sec. 69A.4–69A.4.5; Schedule 53, Seasonal Accredited Capacity Calculation; Schedule 53A, Extended Seasonal Accredited Capacity Calculation. Thus, the Orders’ elimination of capacity treatment for Schahfer and Culley 2 prevents MISO from following its own tariff in the wake of Schahfer and Culley’s 2 continued operation and what will presumably be indefinitely renewed 202(c) orders to force Schahfer and Culley ²⁰ to remain operational. *See* Exhibit 124, U.S. Department of Energy’s November 18, 2025 Emergency Order No. 202-25-9 (issuing a third 90-day 202(c) order forcing the J.H. Campbell Power Plant to remain online); Exhibit 131, U.S. Department of Energy’s November 25, 2025 Emergency Order No. 202-25-10 (issuing a third 90-day 202(c) order forcing the Eddystone Generating Station to remain online).

The Department does not have authority under Section 202(c) to govern ratemaking matters. Under Section 202(c), “the Commission may prescribe by

²⁰ PIOs recognize that the MISO tariff would likely allow Schahfer Unit 18 to not be considered a capacity resource given the extensive repairs needed to return the unit to operation. *See infra* section V.B.2 (discussing the extensive repairs needed to return Schahfer Unit 18 to service); MISO Tariff, Module D, Sec. 64.1.1.xi (describing how units expected to be on outage for more than 31 days in a planning season can decline to participate in the Planning Auction). Regardless, however, the capacity eligibility of Schahfer and Culley 2 should be determined pursuant to the MISO tariff.

supplemental order such terms as it finds to be just and reasonable.” *Id.* The Department of Energy Organization Act transferred authorities of the Federal Power Commission to the Department, except as provided in 42 U.S.C. chapter 84, subchapter IV. 42 U.S.C. § 7151(b). And that subchapter transfers to and vests in the Federal Energy Regulatory Commission “the establishment, review, and enforcement of rates and charges for the transmission or sale of electric energy.” 42 U.S.C. § 7172(a). The capacity treatment of Culley 2 and Schahfer are one such rate matter left exclusively to FERC.

The Orders thus represent a significant and improper intrusion into FERC’s authority to ensure that RTOs like MISO justly and reasonably ensure resource adequacy in their footprint. In particular, the Orders undermine years of FERC’s regulatory oversight of MISO’s resource adequacy construct, as codified in MISO’s FERC-approved tariff. It is within FERC’s purview under Section 205 of the Federal Power Act to provide that oversight, 16 U.S.C. Sec. 824d; and it is within MISO’s purview to apply its own tariff in the first instance and decide whether generators, including Schahfer and Culley 2, should qualify as a “Capacity Resource” within MISO’s FERC-approved resource adequacy construct. 18 C.F.R. § 35.1(e) (“No public utility shall . . . impose any classification, practice, rule, [or] regulation . . . which is different from that provided in a rate schedule required to be on file with this Commission unless otherwise specifically provided by order of the Commission for *good cause shown*.” (emphasis added)).

The Department’s intrusion into the oversight relationship between FERC and the RTOs also runs afoul of the filed rate doctrine, which holds that “no change shall be made [in] any [approved] . . . rate, charge, classification, or service, or in any rule, regulation, or contract relating thereto, except after sixty days’ notice to the Commission and to the public” in another filing with FERC. 16 U.S.C. § 824d(d); *Okla. Gas & Elec. Co. v. FERC*, 11 F.4th 821, 829 (D.C. Cir. 2021). Interference in MISO’s capacity accreditation procedures effectuates a *de facto* change to its tariff, without the legally required notice. And more generally, “Congress rejected a pervasive regulatory scheme for controlling the interstate distribution of power in favor of voluntary commercial relationships. . . . governed in the first instance by business judgment and not regulatory coercion.” *Otter Tail Power*, 410 U.S. at 374. The Department’s interference here in the core operational procedures of MISO’s resource adequacy construct improperly upends that relationship.

More broadly, the result of the Orders not allowing MISO to include Schahfer or Culley 2 in its resource adequacy planning will be MISO securing resources it determines will adequately maintain grid security without Schahfer and Culley 2, pursuant to its FERC-approved tariff. The Orders provide no evidence that MISO cannot be trusted to ensure resource adequacy, so a Department determination that

MISO cannot be trusted would be arbitrary and capricious. It would also conflict with the Department's heavy reliance on MISO's statements and studies in support of its assertion that the region faces an emergency in the first place. Conversely, if the Department lacks the confidence that its own dire predictions that the system does not have enough resources will come true, then it is well short of the confidence necessary for an emergency declaration under Section 202(c).

If left unchecked, this provision could impose completely avoidable cost increases on Indiana and MISO ratepayers. During the pendency of these (unlawful) Orders, the principal effect of this provision will be to remove Schahfer and Culley 2's ability to provide replacement capacity in the event one of the resources that cleared the auction suffers a catastrophic outage or is otherwise suspended, retired, or shut down for more than 31 days in a season. Ex. 134 at 16 (MISO Manual on Resource Adequacy); *see* Ex. 119 (MISO, ZRC Replacement Guidance). Eliminating this compensation pathway will increase the financial cost of the Orders by removing a potential income stream that might have offset Schahfer and Culley 2's extremely high operational costs, and by forcing any other MISO zone that is impacted by an unexpected plant closure to look for potentially more expensive alternatives for replacement capacity.

Additionally, this provision will have an outsized impact in April 2026; this is the very month MISO is conducting its 2026–2027 Planning Auction. Schahfer and Culley 2's exclusion from the list of facilities that might offer capacity will ensure that Indiana ratepayers and MISO ratepayers writ large likely will be forced to pay for Schahfer and Culley 2's continued operation without any countervailing benefits: they will miss out on a major revenue stream that would have reduced Schahfer and Culley 2's operating losses, and, by operation of MISO's sloped demand curve in the Planning Auction which pays more for capacity the scarcer it is, consumers will end up paying a higher premium for any capacity their utilities secure from the Planning Auction.

In short, including this provision is yet another way in which the Department has misapplied the statute: its inclusion only further ensures that Schahfer and Culley 2's principal impact will not be plugging a gap but rather sabotaging MISO's resource planning process and heightening cost burdens in a manner that does not serve the public interest.

D. The Orders Fail to Provide the Conditions Required Under Section 202(c) to Lessen Conflicts with Environmental Standards and Minimize Environmental Harm.

Where an order “may result in a conflict with a requirement of any Federal, State, or local environmental law or regulation, Section 202(c) imposes several

requirements. 16 U.S.C. § 824a(c). The Department must “ensure” that the order “requires generation, delivery, interchange, or transmission of electric energy only during hours necessary to meet the emergency and serve the public interest.” *Id.* § 824a(c)(2). The Department must also “ensure,” “to the maximum extent practicable,” that the order “is consistent with any applicable Federal, State or local environmental law or regulation.” *Id.* Additionally, the Department must ensure that the order minimizes any adverse environmental impacts, regardless of the facility’s compliance (or non-compliance) with environmental standards. *See id.* The Orders violate these statutory obligations.

1. Legal Framework: Section 202(c) Further Limits the Department’s Authority and Mandates Affirmative Steps to Maximize Environmental Compliance and Minimize Environmental Harm Where the Order “May Result in a Conflict” with a Federal, State, or Local Environmental Law or Regulation.

The Federal Power Act obligates the Department to include precautions in a Section 202(c) order where the order “may result in a conflict” with environmental laws or regulations. This is a forward-looking inquiry with a low threshold.²¹

The word “may” in this context denotes a mere possibility, not a certainty. This is especially apparent when matched against the term “shall” used in Section 202(c)(2) and the other provisions added to Section 202(c) at the same time. *See* Fixing America’s Surface Transportation Act of 2015, Pub. L. No. 114-94, 129 Stat. 1312 § 61002 (codified at 16 U.S.C. § 824a). Congress’ use of the two disparate terms must be given effect. *See, e.g., Kingdomware Techs., Inc. v. United States*, 579 U.S. 162, 172 (2016) (discussing significance of the words “may” and “shall” in the same statutory provision).

Moreover, the consequences need not be “noncompliance” or “violation” of environmental law, both of which are terms Congress also used in 2015 adding other provisions to Section 202(c). A potential “conflict” suffices. *Cf. Crosby v. Nat’l Foreign Trade Council*, 530 U.S. 363, 372–73 (2000) (explaining that courts find “conflict” in the preemption context where, for instance, a law or order “stands as an obstacle to the accomplishment and execution of the full purposes and objectives of Congress”). Taken together, anytime a Department order creates circumstances that might obstruct the accomplishment or execution of environmental laws or regulations, Section 202(c)(2) imposes duties on the Department to maximize compliance with the law and minimize adverse environmental effects.

²¹ If actual noncompliance with environmental laws and regulations occurs to carry out the order, the statute provides a safe harbor. 16 U.S.C. § 824a(c)(3).

Congress adopted the requirements of Section 202(c)(2) to address environmental issues arising in response to emergencies on the grid. Congress was well aware of environmental issues stemming from 202(c) orders when it imposed the requirements in Section 202(c)(2). *See, e.g.,* Rolsma, 57 Conn. L. Rev. at 807–09 (discussing prior incidents of tension between environmental requirements and responses to emergencies on the grid, and congressional hearings addressing the matter as part of the passage of Section 202(c)(2)). Congress struck a reasonable balance requiring that environmental concerns not be left by the wayside while the Department responds to actual emergencies. Rather than requiring the Department to engage in a probing review of environmental laws and permits at all levels of our federalist system before acting, Congress set a low threshold for imposition of the mandatory Section 202(c)(2) duties to minimize conflicts with environmental laws and environmental harms flowing from a Section 202(c) order.

2. The Orders May Result in a Conflict with a Federal, State, or Local Environmental Law or Regulation.

Here, the Department implicitly acknowledges the possible conflicts. The Orders are limited to a 90-day duration. Ex. 158 at 9 (March Schahfer Order); Ex. 159 at 9 (March Culley Order). That temporal limitation exists for a 202(c) order that may result in a conflict with environmental requirements. 16 U.S.C. § 824a(c)(4).

Moreover, the evidence shows that the Orders may result in conflicts with environmental requirements. The Schahfer generating plant is subject to the Best Technology Available for Minimizing Adverse Environmental Impact (“BTA”) standards under the National Pollutant Discharge Elimination System (“NPDES”). Specifically, 40 C.F.R. § 125.94 requires that NIPSCO use best technology available to minimize impingement mortality associated with water cooling systems in the Schahfer units. The Units each feature a closed-cycle cooling via a single multi-cell mechanical draft cooling tower. Ex. 24 at 55 (Schahfer 2020 NPDES Permit). The Indiana Department of Environmental Management (“IDEM”) approved Schahfer’s cooling systems as meeting the BTA standard, but stated that: “Primary in this entrainment BTA determination is that the facility will cease operations no later than December 31, 2022 and the permittee does have closed-cycle cooling via a single multi-cell mechanical draft cooling tower on each unit which has allowed the permittee to achieve substantial reductions in water usage.” *Id.* at 55. In other words, IDEM approved Schahfer’s NPDES permit on the flawed assumption that Units 17 and 18 would retire as of December 31, 2022. *Id.* at 1. The NPDES permit expired September 20, 2025. Ex. 24 at 1 (Schahfer 2020 NPDES Permit). As NIPSCO noted, in order to operate Schahfer Units 17 and 18 “for one day beyond 2025,” the Schahfer NPDES permit would require NIPSCO “to install a wastewater treatment system and convert the [retired] Unit 14 and 15 bottom ash handling

system” so that it could be used on Units 17 and 18. Ex. 132 at PDF p. 16 (NIPSCO Rate Case Discovery Responses).

The Order also may result in a conflict with the federal coal combustion residuals (“CCR”) Rule. In 2015 and in subsequent rulemakings, the EPA promulgated rules pursuant to the Resource Conservation and Recovery Act (“RCRA”) which created standards for legacy surface impoundments of CCR. EPA provided an alternative compliance mechanism that extended the deadline for owners and operators to complete closure of their unlined CCR surface impoundments larger than 40 acres until October 17, 2028 if the coal-fired boiler associated with the generator would permanently retire by that same date. 40 C.F.R. § 257.103(f)(2). In its latest compliance filings for the rule, NIPSCO explained that if it ceases combustion of coal at Schahfer by December 31, 2025 as expected, it would be able to close its CCR impoundment (the Waste Disposal Area) by September 17, 2028, a month ahead of EPA’s deadline. Ex. 25A at 6 (Schahfer CCR Part A Demonstration Addendum, part 1). But the Department’s December Schahfer Order in conjunction with the current March Schahfer Order have prevented that closure, which, given the long timeline of closing the Waste Disposal Area, would cause Schahfer to breach the deadline of current federal law.

The March Culley Order also may result in a conflict with environmental laws and regulations. Culley 2 shares pollution control equipment with Culley 3, another generating unit at Culley which is not subject to an order from the Department. Culley 3 contains a flue gas desulfurization (“FGD”) system which serves both units. Ex. 26 at 7 (Culley 2025 Air Permit Modification). Culley Units 3 and 2 also share equipment critical to meeting the units’ NPDES permit requirements. Ex. 56 at 14 (Bradford Coal Inventory Testimony). The result of this setup is that Culley 3 outages can force Culley 2 offline for environmental compliance reasons. Culley 3 saw sustained outages in 2025 that, due to shared pollution control systems, also forced Culley 2 offline. *See* Ex. 27 at 3 (CenterPoint Fuel Cost Order) (describing how “due to the environmental parameters associated with the Culley Unit 3 outage, Culley Unit 2’s availability will be limited until Unit 3 comes back online”). As a result, even if Culley 2 is operational, any downtime needed to service Culley 3 may result in a conflict with environmental requirements.

Independently, running Culley 2 may result in clear conflict with the plant’s NPDES permit. The permit mandates that “[b]eginning December 31, 2025, there shall be no discharge of bottom ash transport water from Unit 2.” Ex. 28 at 6 (Culley 2024 NPDES Permit).

The Orders may result in additional conflicts with air pollution laws and regulations. For example, EPA has approved Indiana’s regional haze state

implementation plan revision. Ex. 57 (2026 EPA IN Haze SIP Approval). Indiana conducted its regional haze state implementation analysis under the assumption that owners of electric generating unit sources would “continue to shutdown units, convert to natural gas, and rely more on renewable energy.” Ex. 69 at 2 (IN Haze SIP Responses to Public Comments); *see also* 90 Fed. Reg. 25,951 (finding Indiana’s choice not to apply the four factor test to all of the state’s EGUs reasonable because given “historical data showing relatively consistent or declining NO_x and SO₂ annual emissions and emission rates, as well as 2028 projections, the overall emissions are not expected to increase in the future”). The Department’s Orders prevent the retirement of Schahfer and Culley 2 and affect how the Plants are dispatched. *See* Ex. 158 at 8–9 (March Schahfer Order); Ex. 159 at 8–9 (March Culley Order). As such, the Orders may result in a conflict with environmental requirements.

3. The Orders Lack the Conditions Required by Section 202(c).

i. The Orders’ Terms Fail to Require Generation Only During Hours Necessary to Meet the Purported Emergency.

The Orders directly contradict the Department’s obligation to require generation “only during hours necessary to meet the emergency.” 16 U.S.C. § 824a(c)(2). The Orders instead state: “For the duration of this Order, MISO is directed to take every step to employ *economic* dispatch” of the Schahfer and Culley 2 Plants “to *minimize cost* to ratepayers.” Ex. 1 at 5 (December Schahfer Order) (emphasis added); Ex. 2 at 5 (December Culley Order) (emphasis added). The “emergency” nominally described by the Orders is the potential “loss of power to homes and businesses in the areas that may be affected by curtailments or power outages.” Ex. 1 at 4 (December Schahfer Order); Ex. 2 at 5 (December Culley Order). Even if the Department had substantiated that emergency (which it has not), the Federal Power Act would allow the Department to compel generation only when needed to prevent such involuntary curtailments or outages. 16 U.S.C. 824a(c)(2).²² “Economic

²² *See, e.g.*, Ex. 6 at 9 (DOE Order No. 202-17-4 Summary of Findings) (“authorizing operation of” units subject to emergency order “only when called upon . . . for reliability purposes,” according to “dispatch methodology” approved by the Department); *see also* Ex. 160 at 7 (Department Order No. 202-26-01) (authorizing specified entities “to direct [certain] backup generation resources . . . to operate as a last resort before declaring an Energy Emergency Alert (EEA) 3 (i.e., before firm load interruption) or during an EEA 3”); Ex. 161 at 7 (Department Order No. 202-26-01A) (authorizing specified entities “to direct [certain] backup generation

dispatch,” in sharp contrast, requires “the lowest-cost resources [to] run first,” in pursuit of “the lowest-cost energy available.” *City of New Orleans v. FERC*, 67 F.3d 947, 948–49 (D.C. Cir. 1995); *see also Fla. Power & Light Co. v. FERC*, 88 F.3d 1239, 1241 (D.C. Cir. 1996) (noting distinction between economic dispatch and reserve capacity rules).

By instructing MISO to employ economic dispatch, the Orders’ terms permit (indeed, direct) operation of Schahfer 17, Schahfer 18, and Culley 2 even when other—albeit potentially higher cost—resources are available that would prevent any “curtailments or power outages”—that is, the claimed emergency. Ex. 158 at 8 (March Schahfer Order); Ex. 159 at 8 (March Culley Order). The Orders’ further instructions—limiting “dispatched units to the times and within the parameters as determined by MISO pursuant to paragraph A,” Ex. 158 at 9 (March Schahfer Order); Ex. 159 at 9 (March Culley Order)—just repeats that initial instruction to “employ economic dispatch,” without any further limitation.²³

ii. The Orders Fail to Ensure Maximum Practicable Consistency with Environmental Rules and to Minimize Adverse Environmental Impacts.

The Orders further fail to “ensure” that Schahfer and Culley 2 operate, “to the maximum extent practicable,” in conformity with applicable environmental rules. 16 U.S.C. § 824(c)(2). The Orders paraphrase the statutory text—that “operation of the [affected units] must comply with applicable environmental requirements . . . to the maximum extent feasible,” but fail to specify *who* bears that responsibility or *what* such operation entails. Ex. 158 at 9 (March Schahfer Order); Ex. 159 at 9 (March Culley Order).²⁴ The direction to “comply . . . to the maximum extent

resources . . . to operate after ERCOT deploys all available market services, except for frequency responsive services, before declaring an Energy Emergency Alert (EEA) 3 (i.e., before firm load interruption) or during an EEA 3”); cf. Ex. 162 at 3 (Department Order No. 202-26-03) (“In the event that ISO-NE determines that generation from the Specified Resources is necessary to meet the electricity demand that ISO-NE anticipates in its service territory, I direct ISO-NE to dispatch such unit or units and to order their operation only as needed to maintain reliability.”).

²³ That direction further fails to conform to the statute’s command to compel only the generation that will “best meet the emergency.” 16 U.S.C. § 824(c)(1).

²⁴ Unlike the previous orders for Schahfer and Culley 2, *see* Ex. 1 at 5 (December Schahfer Order); *see also* Ex. 2 at 5 (December Culley Order), the Orders do not expressly state that “This Order does not provide relief from any obligation to pay

feasible” is, as a result, wholly unenforceable; the Orders provide no basis for the Department, or anyone else, to determine whether each plant is in fact complying or who might face the consequences of any failure to do so. *See* Ex. 9 at 5–7 (DOE Order No. 202-22-4) (requiring, *inter alia*, reporting of “number and actual hours each day” of operation “in excess of permit limits or conditions,” and information describing how generators complied with environmental requirements to maximum extent feasible). Consequently, the Orders do not meet the Department’s statutory obligation to “*ensure*” the maximum feasible consistency with applicable environmental standards—an obligation that requires the Department to offer some discrete guidance as to the Plants’ operations, rather than merely parroting the statutory text. 16 U.S.C. § 824a(c)(2) (emphasis added). In addition, the Orders fail to “minimize[] any adverse environmental impacts.” 16 U.S.C. § 824a(c)(2). That mandate is textually and substantively distinct from the Department’s (also unfulfilled) obligation to ensure maximum practicable compliance with environmental standards. *Id.* The Orders claim to minimize environmental impacts by “limit[ing] operation of dispatched units to the times and within the parameters as determined by MISO, pursuant” to the Orders’ “paragraph A.” Ex. 158 at 9 (March Schahfer Order); Ex. 159 at 9 (March Culley Order). But in both Orders, paragraph A contains only a command that MISO “take all measures necessary to ensure” that the Schahfer and Culley 2 Plants are “available to operate” and “employ economic dispatch . . . to minimize cost to ratepayers,” and requires a directive that NIPSCO and CenterPoint Indiana comply with MISO’s orders implementing the Orders’ commands.²⁵ *Id.* An instruction minimizing ratepayer costs and demanding availability has no rational relationship to a requirement to

fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.” *See* Ex. 158 at 9 (March Schahfer Order); *see also* Ex. 159 at 9 (March Culley Order). The Orders do not, however, state that they provide such relief, that any such relief is necessary to meet the emergency, or otherwise that the agency is changing its position. There is, therefore, no reason to believe that the agency is changing its position.

²⁵ To the extent the Orders allow MISO to independently devise conditions limiting environmental impacts, that mere possibility, first, cannot satisfy the Department’s own statutory obligation to “ensure” that its “order” minimizes environmental impacts (and limits hours to those necessary to meet the emergency, and mandates the maximum practicable compliance). 16 U.S.C. § 824a(c)(2). And even if it could, the Orders require MISO to employ “economic dispatch” and “ensure” that Schahfer and Culley are “available to operate”—directions that are flatly inconsistent with the statute’s requirements to minimize the Plants’ environmental impacts.

minimize environmental impacts. The Orders contain no requirement similar to the requirements recommended by PIOs' expert engineer Mr. Powers: "DOE should require verification of the good working order of the Schahfer 17 and 18 air emission control systems before authorizing Schahfer 17 and 18 to operate under extreme demand conditions" or a similar recommendation for Culley 2. Ex. 4 at 19–20, 22 (Powers January Decl.).

Additionally, the Orders include no measures that would mitigate impacts when compliance with environmental standards proves impracticable—measures that have been routinely included in past orders. *See, e.g.*, Ex. 6 at 9 (DOE Order No. 202-17-4 Summary of Findings) (permitting non-compliant operation only during specified hours, and requiring exhaustion of "all reasonably and practically available resources," including demand response and identified behind-the-meter generation resources selected to minimize an increase in emissions); Ex. 9 at 7 (DOE Order No. 202-22-4) (requiring "reasonable measures to inform affected communities" of non-compliant operations). At a minimum the statute requires the Department to include sufficiently detailed reporting obligations to ascertain what impacts result from emergency operations; without such reporting, the Department has no ability to "ensure" that adverse impacts are minimized. *See, e.g.*, Ex. 110 at 5 (DOE Order No. 202-24-1) (requiring detailed data on emissions of pollutants). The Orders here instead only require "such additional information" as the Department, in the future, may (or may not) "request[] . . . from time to time." Ex. 1 at 5 (December Schahfer Order); Ex. 2 at 5 (December Culley Order). That possibility of future, unspecified inquiry cannot satisfy the statute's demand that the Department "ensure" that its Orders minimize environmental impacts. 16 U.S.C. § 824a(c)(2). As one example of mitigation measures, PIOs' expert engineer, Mr. Powers, suggested that if permit limits for PM, NO_x, or SO₂ are exceeded (as measured on the onsite monitors) during operation of Schahfer 17 and 18 or of Culley 2, the respective units should be shut down. Ex. 4 at 20, 22 (Powers January Decl.). Declining to include such a measure, particularly when there is no apparent risk of loss of power to homes and businesses in the area absent power from Schahfer and Culley 2, does not conform with the requirement of Section 202(c)(2) that the Department order generation only during hours needed to meet the claimed emergency and best serve the public interest.

iii. There is No Indication That the Department Has Conducted the Consultation Required by Section 202(c)(4)(B) or Adopted Conditions Resulting From Consultation.

Finally, there is no indication in the Orders that the Department has, as Section 202(c)(4)(B) requires, "consult[ed] with the primary Federal agency with expertise in the environmental interest protected" by the laws with which the Orders may

conflict. 16 U.S.C. § 824a(c)(4)(B). The Orders serve as a renewal or re-issuance of the Department’s December Schahfer Order and December Culley Order; its claimed basis is that “[t]he emergency conditions that necessitated the issuance of [the prior order] continue.” Ex. 158 at 3 (March Schahfer Order); Ex. 159 at 3 (March Culley Order). But the Department has provided no evidence of consultation with the Environmental Protection Agency (or any other agency with expertise in Schahfer and Culley 2’s air and water pollution). Cf. Ex. 163 at 2 (Department Order No. 202-22-2 Amendment No. 1) (stating that “the Department consulted with EPA... and EPA did not request any additional conditions”); Ex. 167 at 2 (Department Order No. 202-22-1 Amendment No. 2) (same); Ex. 6 at 9–10 (DOE Order No. 202-17-4 Summary of Findings) (including EPA consultation in public record). Nor is there any evidence of “[t]he conditions, if any, submitted” by EPA (or any other agency) following consultation, or “an explanation of [the Department’s] determination” that such conditions “would prevent the [Orders] from adequately addressing the emergency”—material that Section 202(c)(4)(B) requires the Department to make “available to the public.” 16 U.S.C. § 824a(c)(4)(B); *see* Ex. 164 at 1 (Starfield Email to Hoffman) (made public by Department). If the Department has failed to consult and procure the required conditions, it has violated the statute. *Id.* If it has received and declined such conditions, but refused to disclose them or an explanation of why the Department does not believe any such conditions are necessary, that too violates the law. *Id.*

VI. REQUEST FOR STAY

PIOs further move the Department for a stay of the Orders until the conclusion of judicial review. 18 C.F.R. § 385.212.²⁶ The Department has the authority to issue such a stay under the Administrative Procedure Act and should do so where “justice so requires.” 5 U.S.C. § 705. In deciding whether to grant a request for stay, agencies consider (1) whether the party requesting the stay will suffer irreparable injury without a stay; (2) whether issuing a stay may substantially harm other parties; and (3) whether a stay is in the public interest. *Nken v. Holder*, 556 U.S. 418, 434, 436 (2010); *Ohio v. EPA*, 603 U.S. 279, 291 (2024); *see, e.g., Midcontinent Indep. Sys. Operator, Inc.*, 184 FERC ¶ 61,020, at P 41 (2023); *ISO Eng. Inc.*, 178 FERC ¶ 61,063, at P 13 (2022), *rev’d on other grounds sub nom. In re NTE Conn., LLC*, 26 F.4th 980, 987–88 (D.C. Cir. 2022).

²⁶ Pursuant to FPA Section 313(c) and Rule 713(e) of the applicable rules, the filing of a request for rehearing does not automatically stay a Department order. 16 U.S.C. § 825l(c); 18 C.F.R. § 385.713(e).

Injuries under this standard must be actual, certain, imminent, and beyond remediation. *Mexichem Specialty Resins, Inc. v. EPA*, 787 F.3d 544, 555 (D.C. Cir. 2015); *Wis. Gas Co. v. FERC*, 758 F.2d 669, 674 (D.C. Cir. 1985); *ANR Pipeline Co.*, 91 FERC ¶ 61,252, at 61,887 (2000); *City of Tacoma*, 89 FERC ¶ 61,273, at 61,795 (1999) (recognizing that, absent a stay, options for “meaningful judicial review would be effectively foreclosed”). Financial injury is only irreparable where no “adequate compensatory or other corrective relief will be available at a later date, in the ordinary course of litigation.” *Wis. Gas Co.*, 758 F.2d at 674 (quoting *Va. Petroleum Jobbers Ass’n v. Fed. Power Comm’n*, 259 F.2d 921, 925 (D.C. Cir. 1958)); see also *In re NTE Conn., LLC*, 26 F.4th 980, 991 (D.C. Cir. 2022). Environmental injury, however, “can seldom be adequately remedied by money damages and is often permanent or at least of long duration, *i.e.*, irreparable. If such injury is sufficiently likely, therefore, the balance of harms will usually favor the issuance of an injunction to protect the environment.” *Amoco Prod. Co. v. Vill. of Gambell*, 480 U.S. 531, 545 (1987).

Under those standards, a stay of the Orders is appropriate.

A. Intervenor Will Suffer Irreparable Harm Without a Stay of the Orders.

A stay is necessary to protect PIOs, their members, and the public from harm from continued coal-fired power operations caused by the Department’s Orders.

As noted extensively *supra* sec. IV.C.3.i.c and ii.c, Schahfer and Culley 2 emit health- and environment-harming air pollutants like nitrogen oxides, sulfur dioxide, particulate matter, and volatile organic compounds. New coal combustion residuals will continue to pollute groundwater.

The health and environmental harms from this pollution flow directly from the Department’s Orders and are actual, specific, and imminent, and can be deadly. They will affect the lives and well-being of PIOs and their members. The stark public health stakes of PIOs’ request for stay require the Department to pause implementation of its Orders until a court reviews their validity.

Additionally, without a stay, the Orders create other injuries too. The Orders needlessly force NIPSCO and CenterPoint Indiana to continue to divert attention and investment dollars away from planned reuse of the Schahfer and Culley 2 interconnection rights for other generation projects. In doing so, the Department denies PIOs’ members the benefits of Indiana’s energy policies which are designed to benefit them and the public. In addition to forcing ratepayers to pay for the availability and dispatch of uneconomic, unreliable, and obsolete resources that the State, stakeholders, and owners want to close, see *supra* sec. IV.C, the Department’s Orders jeopardize the diversification of generating resources the Department itself

has said increases grid reliability. Ex. 142 (Dep’t of Energy, *Energy Reliability and Resilience*). There is no clear recourse to remedy those injuries either.

B. A Stay Would Not Result in Harm to Any Other Interested Parties.

No other interested parties would be harmed by a stay. The issuance of a stay would not harm end-use electricity consumers because the lack of an actual emergency means that a stay would not disrupt the provision of electricity. *See supra* secs. IV.B–C, V.A. Furthermore, because MISO, the Indiana Commission, NIPSCO, and CenterPoint Indiana have already planned for Schahfer and Culley 2’s closures and continue to plan for resource adequacy, a stay would only have the effect of relieving them of the administrative, compliance, and planning burdens imposed by the Orders. On the balancing of equities, there is therefore no meaningful countervailing harm that would follow from a stay.

C. A Stay Is in the Public Interest Given the Significant Evidence Demonstrating There is No Factual or Legal Support for These Orders, and Given the Harm they Produce to the Broader Public.

There is no public interest served by the Orders, and a stay will only benefit the public. First, the Orders exceed the Department’s authority; the Orders have provided no reasonable grounds to substantiate any near-term or imminent shortfall in electricity supply that would justify Schahfer and Culley 2’s continued operation. *See League of Women Voters v. Newby*, 838 F.3d 1, 12 (D.C. Cir. 2016) (noting “there is a substantial public interest ‘in having governmental agencies abide by the federal laws that govern their existence and operations’”) (quoting *Washington v. Reno*, 35 F.3d 1093, 1103 (6th Cir. 1994)). Second, the Orders override Indiana’s exercise of its “authority to choose [its] preferred mix of energy generation resources.” *Citizens Action*, 125 F.4th at 239. By doing so, the Orders unlawfully intrude into states’ reserved authority over in-state “facilities used for the generation of electric energy.” 16 U.S.C. §824(b)(1); *see Pac. Gas & Elec.*, 461 U.S. at 205 (“Need for new power facilities, their economic feasibility, and rates and services, are areas that have been characteristically governed by the States.”); *see also Hughes*, 578 U.S. at 154 (cleaned up) (“Under the [Federal Power Act], FERC has exclusive authority to regulate the sale of electric energy at wholesale in interstate commerce. . . . But the law places beyond FERC’s power, and leaves to the States alone, the regulation of any other sale—most notably, any retail sale—of electricity.”). And third, a stay would protect the broader public—beyond PIOs and their members—from the onerous costs, and dangerous pollution, produced by unnecessary operation of the Schahfer and Culley 2 Plants.

VII. CONCLUSION

For the reasons set forth above, the undersigned Public Interest Organizations respectfully request that the Department grant intervention with respect to each Order; grant rehearing and rescind the Orders (and any renewals of the Orders); and stay the Orders.

Filed on April 22, 2026.

Submitted by:

[Continued to next page for signatures.]

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Attachment: Index of Exhibits

Index of Exhibits

No.	Exhibit Name	Document Name	URL
1	December Schahfer Order	U.S. Department of Energy's December 23, 2025 Emergency Order No. 202-25-12	https://www.energy.gov/documents/order-number-202-25-12-schahfer
2	December Culley Order	U.S. Department of Energy's December 23, 2025 Emergency Order No. 202-25-13	https://www.energy.gov/documents/order-number-202-25-13-culley
3	EFG Report	Carlos Peña and Anna Sommer of Energy Futures Group, Reliability and Capacity Assessment of F.B. Culley 2 and R.M. Schahfer 17 and 18, January 21, 2026	
4	Powers January Declaration	Schahfer 17 & 18 and Culley 2 Declaration of Bill Powers, P.E., January 21, 2026	
5	Synapse Report	Report of Lucy Metz and Devi Glick of Synapse Energy Economics on cost of continued operation of Culley Unit 2 and Schahfer Units 17–18 under Federal Power Act orders, January 21, 2026	
6	DOE Order No. 202-17-4 Summary of Findings	Summary of Findings DOE Order No. 202-17-4 (Sep. 14, 2017)	https://www.energy.gov/sites/default/files/2017/09/f36/Order%20202-17-4%20Summary%20of%20Findings.pdf
7	DOE Order No. 202-02-1	DOE, Order No. 202-02-1 (Aug. 16, 2002)	https://www.energy.gov/sites/default/files/202%28c%29%20order%20202-02-1%20August%2016%2C%202002%20-%20CSC.pdf

No.	Exhibit Name	Document Name	URL
8	Cooke Email to Alle-Murphy	Email from Lot Cooke, DOE to Linda Alle-Murphy Re: Rehearing procedures for DOE Order No. 202-05-3	https://www.energy.gov/oe/articles/question-and-answer-procedural-questions-application-rehearing-order-no-202-05-02?nrg_redirect=397676
9	DOE Order No. 202-22-4	DOE, Order No. 202-22-4 (Dec. 24, 2022)	https://www.energy.gov/sites/default/files/2022-12/PJM%20202%28c%29%20Order.pdf
10	Grid Strategies June Report	Michael Goggin, <i>A Review of DOE's 202(c) Order for the Campbell Coal Plant</i> (June 18, 2025)	
11	NIPSCO 2025 Planning Reserve Margin Report	NIPSCO 2025 Annual Report in Compliance With Ind. Code § 8-1-8.5-13	https://iurc.portal.in.gov/entity/sharepoint/documentlocation/1a22a22e-cc26-f011-8c4e-001dd8084fd9/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=46233 NIPSCO Submission%20of%20Redacted%20Report 05012025.pdf
12	CenterPoint 2025 Planning Reserve Margin Report	CenterPoint Energy Indiana South 2025 HEA 1520 Report Pursuant to I.C. § 8-1-8.5-13 (May 23, 2025)	https://iurc.portal.in.gov/entity/sharepoint/documentlocation/e865df14-0c38-f011-8c4e-001dd80846ac/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=46236 CEIS Notice%20of%20Submission%20of%20HEA%201520%20Report 052325.pdf
13	NIPSCO Performance Metric Collaborative Update	Northern Indiana Public Service Company LLC's Annual Performance Metric Collaborative Update, IURC Cause No. 44688, July 1, 2025	https://iurc.portal.in.gov/entity/sharepoint/documentlocation/9847a67d-a756-f011-877b-001dd8084fd9/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=44688 NIPSCO Compliance%20Filing%20-%20PMC%20Update 07012025.pdf
14	Saffran Q1 2025 Outage Testimony	Direct Testimony of David Saffran on behalf of Northern Indiana Public Service	https://iurc.portal.in.gov/entity/sharepoint/documentlocation/0f58f29b-f637-f011-8c4e-001dd80846ac/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=38706FAC147 NIPSCO

No.	Exhibit Name	Document Name	URL
		Company LLC, IURC Cause No. 38706 FAC 147, May 23, 2025	Petitioners%20Exhibit%204%20(Saffran) 05232025.pdf
15	Saffran Q2 2025 Outage Testimony	Direct Testimony of David Saffran on behalf of Northern Indiana Public Service Company LLC, IURC Cause No. 38706 FAC 148, Aug. 18, 2025	https://iurc.portal.in.gov/entity/sharepoint/documentlocation/635d1149-747c-f011-b4cc-001dd80846ac/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=38706FAC148 NIPSCO Petitioners%20Exhibit%204%20(Saffran) 08182025.pdf
16	Saffran Q3 2025 Outage Testimony	Direct Testimony of David Saffran on behalf of Northern Indiana Public Service Company LLC, IURC Cause No. 38706 FAC 149, Nov. 20, 2025	https://iurc.portal.in.gov/entity/sharepoint/documentlocation/e268e77b-52c6-f011-bbd3-001dd8084fd9/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=38706FAC149 NIPSCO Petitioners%20Exhibit%204%20(Saffran) 11202025.pdf
17	DOE Order No. 202-20-2	Department of Energy Order No. 202-20-2 (Sept. 6. 2020)	https://www.energy.gov/oe/articles/federal-power-act-section-202c-caiso-september-2020?nrg_redirect=454296
18	Wagner November Testimony	Direct Testimony of John A. Wagner on behalf of Northern Indiana Public Service Company LLC, IURC Cause No. 38706 FAC 149, Nov. 20, 2025	https://iurc.portal.in.gov/entity/sharepoint/documentlocation/08174aa0-52c6-f011-bbd3-001dd8084fd9/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=38706FAC149 NIPSCO Petitioners%20Exhibit%203%20(Wagner) 11202025.pdf
19	NIPSCO CPCN Discovery Responses	IURC Cause No. 45947, NIPSCO-CAC Joint Exhibit 6 (NIPSCO's Public Responses to CAC Data Requests), July 11, 2024	https://iurc.portal.in.gov/entity/sharepoint/documentlocation/98b5e199-824b-ef11-a316-001dd8073c71/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=45947%20NIPSCO.CAC%20Joint%20Exhibit%20No.%206.pdf

No.	Exhibit Name	Document Name	URL
20	IURC Schahfer Gas Plant Order	Indiana Utility Regulatory Commission Order in Cause No. 45947 dated October 16, 2024	https://iurc.portal.in.gov/entity/sharepoint/documentlocation/8d902453-cd8b-ef11-ac21-001dd80bd98a/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=ord_45947_101624.pdf
21	CenterPoint Indiana 2025 IRP	CenterPoint Energy Indiana South 2025 Integrated Resource Plan	https://www.in.gov/iurc/files/CEIS_2025_IRP_Volume_1_of_2.pdf
22	CenterPoint 2024 Performance Report	CenterPoint Energy Indiana South 2024 Electric Performance Report	https://iurc.portal.in.gov/entity/sharepoint/documentlocation/ec855054-7c53-f011-877a-001dd80846ac/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=45564_CEI%20South_Electric%20Performance%20Report_062725.pdf
23	Wayne Games 2021 Testimony	Rebuttal Testimony of Wayne D. Games To The Direct Testimony Of Intervening Parties On Need For Resources To Replace Existing Inefficient Units, Cause No. 45501 (May 24, 2021).	https://iurc.portal.in.gov/entity/sharepoint/documentlocation/76eb9f24-6ebd-eb11-8236-001dd802dc58/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=45501_CenterPoint%20Energy%20Indiana%20South_Games%20Rebuttal%20Testimony%20Petitioners%20Exhibit%20No%203-R%20(PUBLIC)_052421.pdf
24	Schahfer 2020 NPDES Permit	Indiana Dept. of Env'tl. Mgmt. Approval of Schahfer Generating Station NPDES Permit Application (Sep. 24, 2020)	https://ecm.idem.in.gov/cs/idcplg?IdcService=GET_FILE&dID=83057089&dDocName=83057294&Rendition=web&allowInterrupt=1&noSaveAs=1
25A	Schahfer CCR Part A Demonstration Addendum, part 1	NIPSCO R.M. Schahfer Generating Station: Demonstration of Site-Specific Alternative Deadline to Initiate Closure of CCR Surface Impoundment Due to Permanent Cessation of	https://www.nipsco.com/docs/librariesprovider1/rates-and-tariffs/ccr/r.m.-schahfer/r.m.-schahfer-generating-station-groundwater-monitioring-and-corrective-action/rm-schahfer-generating-station-wda-part-a-addendum-2-summer-2022.pdf?sfvrsn=d2e31151_3

No.	Exhibit Name	Document Name	URL
		Coal-fired Boilers by a Date Certain – Addendum 2 (August 2022), PDF pp. 1–191	
25B	Schahfer CCR Part A Demonstration Addendum, part 2	NIPSCO R.M. Schahfer Generating Station: Demonstration of Site-Specific Alternative Deadline to Initiate Closure of CCR Surface Impoundment Due to Permanent Cessation of Coal-fired Boilers by a Date Certain – Addendum 2 (August 2022), PDF pp. 192-466.	(Same as Exhibit 25A)
25C	Schahfer CCR Part A Demonstration Addendum, part 3	NIPSCO R.M. Schahfer Generating Station: Demonstration of Site-Specific Alternative Deadline to Initiate Closure of CCR Surface Impoundment Due to Permanent Cessation of Coal-fired Boilers by a Date Certain – Addendum 2 (August 2022), PDF pp. 467-691	(Same as Exhibit 25A)
26	Culley 2025 Air Permit Modification	Indiana Dept. of Env'tl. Management, Minor Permit Modification to Part 70 Operating Permit No. T173-43264-00001 (July 7, 2025), PDF pp. 1–191	https://ecm.idem.in.gov/cs/idcplg?IdcService=GET_FILE&dID=83826642&dDocName=83830685&Rendition=web&allowInterrupt=1&noSaveAs=1
27	CenterPoint Fuel Cost Order	IURC Order, Cause No. 38708 FAC 146, April 30, 2025	https://iurc.portal.in.gov/entity/sharepoint/documentlocation/08b0fe52-d625-f011-998a-001dd80b1717/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=ord_38708FAC146_043025.pdf

No.	Exhibit Name	Document Name	URL
28	Culley 2024 NPDES Permit	Indiana Dept. of Env'tl. Management, Modification to NPDES Permit No. IN0002259, May 3, 2024	https://ecm.idem.in.gov/cs/idcplg?IdcService=GET_FILE&dID=83630044&dDocName=83634089&Rendition=web&allowInterrupt=1&noSaveAs=1
29	Bradford 2025 CCR Testimony	Direct Testimony of F. Shane Bradford on behalf of CenterPoint Energy Indiana South, IURC Cause No. 45052 ECA 6, May 7, 2025	https://iurc.portal.in.gov/entity/sharepoint/documentlocation/1f3f3a58-3b2c-f011-8c4e-001dd8084fd9/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=45052%20ECA%206_CE_I%20South_Pet.%27s%20Ex.%20No.%201_Bradford%20Direct%20Testimony%20and%20Attachment_050725%20(2).pdf
30	DOE Rehearing Procedures	U.S. Dep't of Energy, DOE 202(c) Order Rehearing Procedures (last visited June 17, 2025)	https://www.energy.gov/ceser/doe-202c-order-rehearing-procedures
31	MISO 2025–26 Auction Results	MISO, Planning Resource Auction, Results for Planning Year 2025-2026 (Apr. 2025)	https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf
32	MISO Emergency Declarations	MISO, Maximum Generation Emergency Declarations through June 2024 (Aug. 30, 2024)	https://www.oasis.oati.com/woa/docs/MISO/MISOdocs/Capacity_Emergency_Historical_Information.pdf
33	MISO Market Capacity Emergency	MISO, Market Capacity Emergency, SO-P-EOP-11-002 Rev: 23 (Oct. 15, 2025)	https://cdn.misoenergy.org/SO-P-EOP-11-002%20Rev%2023%20MISO%20Market%20Capacity%20Emergency683501.pdf
34	Ramey MISO Comments	Comments of Todd Ramey on Behalf of Midcontinent ISO, Inc. (May 28, 2025), Docket No. AD24-11-000, Accession No. 20250528-4032	https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250528-4032&optimized=false&sid=4f4f3475-8309-4416-8289-2aee6d84c1a8

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35	Patton MISO Comments	Technical Conference Comments of David B. Patton, Ph.D., MISO Independent Market Monitor (May 28, 2025), Docket No. AD25-7-000, Accession No. 20250528-4006	https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250528-4006&optimized=false&sid=2c5ac909-a7f0-47eb-9bb3-c35f89976250
36	MISO Elliott Max. Gen. Event Overview	MISO, Overview of Winter Storm Elliott December 23, Maximum Generation Event (Jan. 17, 2023)	https://cdn.misoenergy.org/20230117%20RSC%20Item%2005%20Winter%20Storm%20Elliott%20Preliminary%20Report627535.pdf
37	MISO 2025–2026 CIL/CEL Final Results	MISO, 2025-2026 PY Seasonal CIL/CEL Final Results (Oct. 24, 2024)	https://cdn.misoenergy.org/20241024%20LOLEWG%20Item%2004%20PY%202025-2026%20Final%20CIL%20CEL%20Results654989.pdf
38	MISO LOLE Presentation	MISO, <i>LOLE 101: Probabilistic Analyses</i>	https://cdn.misoenergy.org/LOLE%20101%20Training624875.pdf
39	DOE Order No. 202-22-2	Department of Energy Order No. 202-22-2 (Sept. 4, 2022)	https://www.energy.gov/ceser/federal-power-act-section-202c-banc-september-2022
40	NERC 2024 Reliability Report	NERC, 2024 State of Reliability (June 2024) (excerpt)	https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC SOR 2024 Technical Assessment.pdf
41	NERC 2025 Summer Reliability Assessment	NERC, 2025 Summer Reliability Assessment (May 2025)	https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC SRA 2025.pdf

No.	Exhibit Name	Document Name	URL
42A	2019–24 NERC Summer Reliability Assessments, part 1	NERC, Summer Reliability Assessments for 2019–2024 (Compiled), PDF pp. 1–89	<u>2019 Reliability Assessment:</u> https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC SRA 2019.pdf <u>2020 Reliability Assessment:</u> https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC SRA 2020.pdf <u>2021 Reliability Assessment:</u> https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC SRA 2021.pdf <u>2022 Reliability Assessment:</u> https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC SRA 2022.pdf <u>2023 Reliability Assessment:</u> https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC SRA 2023.pdf <u>2024 Reliability Assessment:</u> https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC SRA 2024.pdf
42B	2019–24 NERC Summer Reliability Assessments, part 2	NERC, Summer Reliability Assessments for 2019–2024 (Compiled), PDF pp. 90–176	(Same as Exhibit 42A)
42C	2019–24 NERC Summer Reliability Assessments, part 3	NERC, Summer Reliability Assessments for 2019–2024 (Compiled), PDF pp. 177–264	(Same as Exhibit 42A)

No.	Exhibit Name	Document Name	URL
43	Winter Storm Elliott System Operations Inquiry	FERC, NERC, and Regional Entity Staff Report, Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott (Oct. 2023)	https://www.ferc.gov/media/winter-storm-elliott-report-inquiry-bulk-power-system-operations-during-december-2022#
44	PJM Elliott Report	PJM, <i>Winter Storm Elliott: Event Analysis and Recommendation Report</i> (July 17, 2023)	https://www.pjm.com/-/media/DotCom/library/reports-notice/special-reports/2023/20230717-winter-storm-elliott-event-analysis-and-recommendation-report.pdf?ref=blog.gridstatus.io
45	DOE Order No. 202-21-1	Department of Energy Order No. 202-21-1 (Feb. 14, 2021)	https://www.energy.gov/oe/articles/federal-power-act-section-202c-ercot-february-2021?nrg_redirect=364318
46	FERC Energy Primer	FERC, <i>Energy Primer: A Handbook of Energy Market Basics</i> (Dec. 2023) (excerpt)	https://www.ferc.gov/media/energy-primer-handbook-energy-market-basics
47	MISO Schedule 53 Class Averages	MISO, Planning Year 2026-2027 Preliminary Schedule 53 Class Averages	https://cdn.misoenergy.org/Initial%20Schedule%2053%20Class%20Average%20for%20PY26-27733034.pdf
48	Utility Dive, MISO begins reviewing 6.1 GW — 70% of it gas — in fast-track interconnection study (Dec. 2, 2025)	Ethan Howland, Utility Dive, MISO begins reviewing 6.1 GW — 70% of it gas — in fast-track interconnection study (Dec. 2, 2025)	https://www.utilitydive.com/news/miso-eras-fast-track-interconnection-study-gas/806747/
49	2025 Energy Innovation Dataset	Energy Innovation, dataset for Coal Power 28 Percent More	https://energyinnovation.org/report/coal-power-28-percent-more-expensive-in-2024-than-in-2021/

No.	Exhibit Name	Document Name	URL
		Expensive In 2024 Than In 2021 (June 5, 2025)	
50	2025 Energy Innovation Coal Cost Report	Energy Innovation, Coal Power 28 Percent More Expensive In 2024 Than In 2021 (June 5, 2025)	https://energyinnovation.org/wp-content/uploads/Coal-Cost-Update.pdf
51	2023 Energy Innovation Coal Cost Report	Energy Innovation, Coal Cost Crossover 3.0 (Jan. 2023)	https://energyinnovation.org/wp-content/uploads/Coal-Cost-Crossover-3.0-2.pdf
52	Department Export Authorization EA-365-C (Oct. 21, 2025)	Research Power Corp., Order No. EA365-C (Oct. 21, 2025)	https://www.energy.gov/sites/default/files/2025-11/EA-365-C%20Research%20Power%20Corporation%20-%20Export%20Authorization%20Order.pdf
53	IURC 2025 Winter Reliability Forum (December 2, 2025)	Excerpt in .MP4 format of video recording of IURC 2025 Winter Reliability Forum (December 2, 2025),beginning at 51:35 timestamp	https://www.youtube.com/watch?v=bCzALF4V45M
54	NARUC Coal Report	National Association of Regulatory Utility Commissioners, Recent Changes to U.S. Coal Plant Operations and Current Compensation Practices (Jan. 2020) (excerpt)	https://www.osti.gov/servlets/purl/1869928
55	IEA Flexibility Report	C. Henderson, International Energy Agency, Increasing the flexibility of coal-fired power plants (Sept. 2014) (excerpt)	https://usea.org/sites/default/files/092014_Increasing%20the%20flexibility%20of%20coal-fired%20power%20plants_ccc242.pdf

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56	Bradford Coal Inventory Testimony	Direct Testimony of F. Shane Bradford on behalf of CenterPoint Energy Indiana South, IURC Cause No. 38708 FAC 149, Nov. 17, 2025	https://iurc.portal.in.gov/entity/sharepoint/documentlocation/54dd55d5-bbc4-f011-bbd3-001dd8084346/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=38708FAC149 CEI%20South%20Electric No%201%20Bradford%20Testimony%20and%20Attachments%20PUBLIC 111725.pdf
57	2026 EPA IN Haze SIP Approval	Air Plan Approval; Indiana; Regional Haze Plan for the Second Implementation Period	https://www.federalregister.gov/documents/2026/01/26/2026-01406/air-plan-approval-indiana-regional-haze-plan-for-the-second-implementation-period
58	MISO Tariff Module E-1	MISO Tariff Module E-1 – Resource Adequacy	https://docs.misoenergy.org/miso12-legalcontent/Module_E-1 - Resource Adequacy.pdf
59	[Omitted.]		
60	MISO Tariff Section 38.2.7	MISO Tariff Section 38.2.7	https://docs.misoenergy.org/miso12-legalcontent/Module_C - Energy and Operating Reserve Markets.pdf
61	MISO Tariff Attachment Y	MISO Tariff Attachment Y	https://docs.misoenergy.org/miso12-legalcontent/Attachment Y - Notification of Potential Resource - SCU Change of Status.pdf
62	FERC Technical Conference Notice	FERC, <i>Meeting the Challenge of Resource Adequacy in Regional Transmission Organization and Independent System Operator Regions</i> (June 2, 2025)	https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250602-3068&optimized=false&sid=457eb824-f5ed-41fa-a043-a0cd8c55cb4b

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63	Palgrave Handbook	M. Hafner & G. Luciana, Palgrave Handbook of International Economics (2022) (excerpt)	https://link.springer.com/book/10.1007/978-3-030-86884-0
64	IEA Report	International Energy Agency, The role of CCUS in low-carbon power systems (2020) (excerpt)	https://www.iea.org/reports/the-role-of-ccus-in-low-carbon-power-systems
65	DOE Transmission Planning Study	DOE, Nat'l Transmission Planning Study, Ch. 2: Long-Term U.S. Transmission Planning Scenarios (2024)	https://www.energy.gov/sites/default/files/2024-10/NationalTransmissionPlanningStudy-Chapter2.pdf
66	NERC 2024 Interregional Transfer Capability Study, Part 1	NERC, Interregional Transfer Capability Study: (ITCS) Strengthening Reliability Through the Energy Transformation, Transfer Capability Analysis (Part 1) (Aug. 2024)	https://www.nerc.com/pa/RAPA/Documents/ITCS_Part_1_Results.pdf
67	[Omitted.]		
68	Grid Strategies Sept. Report	Michael Goggin, <i>A Review of DOE's Second 202(c) Order for the Campbell Coal Plant</i> (Sept. 2025)	
69	IN Haze SIP Responses to Public Comments	Appendix V, Regional Haze State Implementation Plan Responses to Public Comments (Dec. 29, 2021)	https://downloads.regulations.gov/EPA-R05-OAR-2021-0963-0002/attachment_22.pdf

No.	Exhibit Name	Document Name	URL
70	Konidena September Declaration	Declaration of Rao Konidena (Sept. 3, 2025) (including attachment)	
71	NIPSCO 2018 IRP	Northern Indiana Public Company LLC 2018 Integrated Resource Plan, October 2018	https://www.in.gov/iurc/files/2018-NIPSCO-IRP.pdf
72A	NIPSCO 2021 IRP, part 1	Northern Indiana Public Company LLC 2021 Integrated Resource Plan (October 2021), PDF pp. 1–169	https://www.in.gov/iurc/files/NIPSCO_2021-Integrated-Resource-Plan-Documents-1.pdf
72B	NIPSCO 2021 IRP, part 2	Northern Indiana Public Company LLC 2021 Integrated Resource Plan (October 2021), PDF pp. 170–324	(Same as Exhibit 72A)
73	NIPSCO May 2022 Investor Call	NiSource reports first quarter 2022 results	https://www.nisource.com/news/article/nisource-reports-first-quarter-2022-results-20220504
74	DOE 202(c) Webpage as of Apr. 22, 2026	U.S. Dep’t of Energy, DOE’s Use of Federal Power Act Emergency Authority (last visited Apr. 22, 2026)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority
75	MISO Tariff Zonal Map	MISO, Attachment VV to FERC-Approved Tariff	https://etariff.ferc.gov/TariffBrowser.aspx?id=1162
76	Secretary Wright’s West Virginia Remarks	Charles Young, West Virginia News, <i>Energy Secretary Chris Wright: Future of U.S. Coal is “long and bright”</i> (July 5, 2025)	https://www.wvnews.com/news/wvnews/energy-secretary-chris-wright-future-of-u-s-coal-is-long-and-bright/article_948eb88e-2509-42a3-b985-07c47f1ee151.html

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77	MISO 2021 Transmittal Letter	Transmittal Letter, FERC Docket No. ER22-495-000 (Nov. 30, 2021), Accession No. 20211130-5166	https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20211130-5166
78	NiSource 2024 Annual Report	NiSource Inc. 2024 Annual Report (Form 10-K)	https://www.nisource.com/docs/librariesprovider2/sustainability-archives/2024/nisource-2024-annual-report.pdf?sfvrsn=2068f951_6
79	CenterPoint 2024 Annual Report	CenterPoint Energy, Inc. Form 10-K (2024 Annual Report) dated March 4, 2025	https://investors.centerpointenergy.com/static-files/b4884cf5-749f-46ad-9f89-3507d71a725c
80	CenterPoint Indiana 2025 IRP Summary	Executive Summary, CenterPoint Energy Indiana South 2025 Integrated Resource Plan	https://www.in.gov/iurc/files/CEIS_2025_IRP-Non-Technical_Summary.pdf
81	Joundi Testimony	Testimony of Zakaria Joundi, FERC Docket No. ER24-1638 (Mar. 28, 2024), Accession No. 20240328-5329 (Tab E)	https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20240328-5329
82	MISO 2024–25 LOLE Study Report	MISO, Planning Year 2024-2025 Loss of Load Expectation Study Report (April 2024)	https://cdn.misoenergy.org/LOLE%20Study%20Report%20PY%202024-2025631112.pdf
83	MISO 2025–26 LOLE Study Report	MISO, Planning Year 2025-2026 Loss of Load Expectation Study Report (April 2025)	https://cdn.misoenergy.org/PY%202025-2026%20LOLE%20Study%20Report685316.pdf?v=20250313114401
84	MISO 2024–25 Auction Results	MISO, Planning Resource Auction Results for Planning Year 2024-25 (Corrected) (April 26, 2024)	https://cdn.misoenergy.org/2024%20PRA%20Results%20Posting%2020240425632665.pdf

No.	Exhibit Name	Document Name	URL
85	MISO Attributes Roadmap	MISO Attributes Roadmap (Dec. 2023)	https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf
86	MISO Attributes Roadmap Technical Appendix	MISO, Technical Appendix: Attributes Roadmap (June 2024)	https://cdn.misoenergy.org/2023%20Attributes%20Technical%20Appendix631176.pdf
87	MISO's Response to the Reliability Imperative	MISO's Response to the Reliability Imperative (Feb. 2024)	https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf
88	Schahfer Waste Disposal Area Closure Plan	NIPSCO LLC R.M. Schahfer Generating Station Waste Disposal Area Closure Plan – Version #5 (October 2020)	https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/ccr/r.m.-schahfer/r.m.-schahfer-generating-station-closure-and-post-closure-care/r-m-schahfer-generating-station---waste-disposal-area-closure-plan.pdf?sfvrsn=78977151_8
89	2025 OMS-MISO Survey	2025 OMS-MISO Survey Results (June 6, 2025)	https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf
90	MISO ERAS Transmittal Letter	Re: Midcontinent Independent System Operator, Inc. Revisions to the Open Access Transmission, Energy and Operating Reserve Tariff Expedited Resource Addition Study Filing, Docket No. ER25-2454-000 (June 6, 2025), Accession No. 20250606-5228	https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250606-5228&optimized=false&sid=c2678d58-1762-48e9-bcca-059a2a848538
91	MISO ERAS Decision	Order Accepting Tariff Revisions, Subject to Condition, 192 FERC 61,064 (July 21, 2025)	https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250721-3077&optimized=false&sid=c2678d58-1762-48e9-bcca-059a2a848538

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92	Energy Emergency EO	Exec. Order No. 14,156, 90 Fed. Reg. 8433, Declaring a National Energy Emergency (Jan. 29, 2025)	https://www.govinfo.gov/content/pkg/DCPD-202500123/pdf/DCPD-202500123.pdf
93	Grid EO	Exec. Order No. 14,262, 90 Fed. Reg. 15521, Strengthening the Reliability and Security of the U.S. Electric Grid (Apr. 14, 2025)	https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid
94	NY Times Coal Article	Brad Plumer & Mira Rojanasakul, <i>Trump Signs Orders Aimed at Reviving a Struggling Coal Industry</i> , NY Times (Sept. 3, 2025).	https://www.nytimes.com/2025/04/08/climate/trump-order-coal-mining.html
95	EIA Table 8.4	U.S. Energy Information Administration Electric Power Annual, Table 8.4: Average power plant operating expenses for major U.S. investor-owned electric utilities	https://www.eia.gov/electricity/annual/table.php?t=epa_08_04.html
96	July 2025 Resource Adequacy Report	DOE, Resource Adequacy Report: Evaluating the Reliability and Security of the United States Grid (July 2025)	https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf
97	DOE July 7, 2025 Press Release	<i>DOE, Department of Energy Releases Report on Evaluating U.S. Grid Reliability and Security</i> (July 7, 2025)	https://www.energy.gov/articles/department-energy-releases-report-evaluating-us-grid-reliability-and-security

No.	Exhibit Name	Document Name	URL
98	Culley East Ash Pond Closure Plan	Southern Indiana Gas and Electric Company Written Closure Plan 257.102(b) and (d) for the East Ash Pond at the F.B. Culley Generating Station, Revision 1 (September 2021)	https://www.centerpointenergy.com/en-us/Documents/CCR-Reporting/Culley-Station-Closure/Culley-East-Closure-Plan-Rev-1.pdf
99	RFR of July Resource Adequacy Report	Motion to Intervene and Request for Rehearing of Natural Resources Defense Council, the Ecology Center, Environmental Defense Fund, Environmental Law and Policy Center, Public Citizen, Sierra Club, and Vote Solar, DOE Resource Adequacy Report (Aug. 8, 2025).	https://sustainableferc.org/wp-content/uploads/2025/08/2025-08-06_NRDC-et-al-Request-for-Rehearing-DOE-Resource-Adequacy-Report.pdf
100A	NIPSCO 2024 IRP, part 1	Northern Indiana Public Service Company LLC 2024 Integrated Resource Plan (Dec. 9, 2024), PDF pages 1–119	https://www.in.gov/iurc/files/NIPSCO-2024-Integrated-Resource-Plan-Document.pdf
100B	NIPSCO 2024 IRP, part 2	Northern Indiana Public Service Company LLC 2024 Integrated Resource Plan (Dec. 9, 2024), PDF pages 120–239	(Same as Exhibit 100A)
100C	NIPSCO 2024 IRP, part 3	Northern Indiana Public Service Company LLC 2024 Integrated Resource Plan (Dec. 9, 2024), PDF pages 240–358	(Same as Exhibit 100A)

No.	Exhibit Name	Document Name	URL
101	Schahfer Title V Permit Modification, Feb. 2025	Northern Indiana Public Service Company LLC - R.M. Schahfer Generating Station, Significant Permit Modification No. 073-48085-00008, February 4, 2025	https://ecm.idem.in.gov/cs/idcplg?IdcService=GET_FILE&dID=83755127&dDocName=83759170&Rendition=web&allowInterrupt=1&noSaveAs=1
102	MISO Attachment Y Response to NIPSCO	NIPSCO Notice of Planned Participation under 40 C.F.R. 423.19(h), Oct. 29, 2025 (including letter from MISO dated Feb. 3, 2023)	https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/elg/schahfer-notice-of-planned-participation---elg-rule-2034-subcategory.pdf?sfvrsn=58f9f251_1
103	NIPSCO 2019 Rate Order	IURC Order, Cause No. 45159, Dec. 4, 2019	https://iurc.portal.in.gov/entity/sharepoint/documentlocation/ac4c36e7-ae16-ea11-a997-001dd800b582/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=45159%20ORDER%2020191204101716836.pdf
104	NIPSCO 2023 Rate Order	IURC Order, Cause No. 45772, Aug. 2, 2023	https://iurc.portal.in.gov/entity/sharepoint/documentlocation/a4adc395-4031-ee11-bdf4-001dd80abde3/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=ord_45772_080223.pdf
105	DOE Order No. 202-08-1	DOE Order No. 202-08-1 (Sept. 14, 2008)	https://www.energy.gov/sites/prod/files/202%28c%29%20order%20202-08-1%20September%2014%2C%202008%20-%20CenterPoint%20Energy.pdf
106	NIPSCO 2025 Rate Order	IURC Order, Cause No. 46120, June 26, 2025	https://iurc.portal.in.gov/entity/sharepoint/documentlocation/05bff4f4-a952-f011-877a-001dd80b1717/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=ord_46120_062625.pdf
107	Vectren 2014 IRP	Vectren Energy Delivery of Indiana, Inc. 2014 Integrated Resource Plan, November 2014	https://www.in.gov/iurc/files/SIGECO-Vectren_2014_IRP_Report.pdf

No.	Exhibit Name	Document Name	URL
108	Vectren 2016 IRP	Vectren Energy Delivery of Indiana, Inc. 2016 Integrated Resource Plan, December 2016	https://www.in.gov/iurc/files/SIGECO-2016-IRP.pdf
109	Culley East Ash Pond Extension Demonstration	Southern Indiana Gas and Electric Company Request for Site-Specific Alternative Deadline to Initiate Closure of CCR Surface Impoundment (November 2020)	https://www.centerpointenergy.com/en-us/Documents/CCR-Reporting/Culley-Station-Closure/Culley-East-Site-Specific-Alternative-to-Initiate-Closure_FINAL.pdf
110	DOE Order No. 202-24-1	DOE Order No. 202-24-1 (Oct. 9, 2024)	https://www.energy.gov/sites/default/files/2024-10/Duke%20202%28c%29%20Order_100924%20FINAL_JMG%20signed.pdf
111	[Omitted.]		
112	Witmeier 2024 Queue Cap Testimony	Errata to Att. X Queue Cap Proposal and Exemptions to Queue Cap, Tab A, Prepared Direct Testimony of Andrew Witmeier, at 21:4, Docket No. ER25-507-000 (Nov. 21, 2024) (“Witmeier 2024 Queue Cap Testimony”), Accession No. 20241213-5063.	https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20241213-5063&optimized=false&sid=1e90ede4-da17-4482-8e6d-e346192d0609
113	Inst. Pol’y Integrity Report	Inst. Pol’y Integrity, Enough Energy: A Review of DOE’s Resource Adequacy Methodology (July 2025)	https://policyintegrity.org/files/publications/IPI_EnoughEnergy_FinalReport.pdf

No.	Exhibit Name	Document Name	URL
114	IURC 2019 CCGT Order	IURC Order, Cause No. 45052, April 24, 2019	https://iurc.portal.in.gov/entity/sharepoint/documentlocation/4dfb39e0-9f66-e911-8151-1458d04ef938/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=45052_ord_20190424102046480.pdf
115	Vectren 2020 IRP	Vectren 2019/2020 Integrated Resource Plan, June 2020	https://www.in.gov/iurc/files/2019-2020-Vectren-IRP-Volume-1-of-2.pdf
116	CenterPoint 2023 IRP	CenterPoint Energy Indiana South 2022/2023 Integrated Resource Plan, May 2023	https://www.in.gov/iurc/files/2022-2023-CNP-IRP-Volume-1-of-2-Redacted.pdf
117	RTO Insider Article	John Cropley & Amanda Durish Cook, DOE Orders Mich. Coal Plant to Remain Available Another 90 Days, RTO Insider (Aug. 21, 2025).	https://www.rtoinsider.com/113044-doe-orders-mich-coal-plant-to-remain-available-another-90-days/
118	RMI Analysis of Coal Plants' Threats to Reliability	Gabriella Tosado, Ashtin Massie & Joe Daniel, <i>Reality Check: We Have What's Needed to Reliably Power the Data Center Boom, and It's Not Coal Plants</i> , RMI (Aug. 12, 2025)	https://rmi.org/reality-check-we-have-whats-needed-to-reliably-power-the-data-center-boom-and-its-not-coal-plants/
119	MISO, ZRC Replacement Guidance	ZRC replacement and instructions in the MECT, Resource Adequacy Subcommittee (May 5, 2023)	https://cdn.misoenergy.org/20230524%20RASC%20Item%2004b%20ZRC%20Replacement628921.pdf
120	2024 OMS-MISO Survey	2024 OMS-MISO Survey Results (June 20, 2024)	https://cdn.misoenergy.org/20240620%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation635585.pdf

No.	Exhibit Name	Document Name	URL
121	Witmeier 2025 ERAS Testimony	Prepared Direct Testimony of Andrew Witmeier, FERC Docket No. ER25-2454-000, (June 6, 2025), Accession No. 20250606-5228	https://elibrary.ferc.gov/eLibrary/filelist?accession_Number=20250606-5228
122	GridLab Report	GridLab Analysis: Department of Energy Resource Adequacy Report (July 11, 2025)	https://gridlab.org/gridlab-analysis-department-of-energy-resource-adequacy-report/
123	Duke University Rethinking Load Growth Study	Tyler H. Norris et al., Rethinking Load Growth: Assessing the Potential for Integration of Large Flexible Loads in US Power Systems, Duke University Nicholas Institute for Energy, Environment & Sustainability (Feb. 2025)	https://nicholasinstitute.duke.edu/sites/default/files/publications/rethinking-load-growth.pdf
124	November Campbell Order	DOE Order No. 202-25-9 (November 18, 2025)	https://www.energy.gov/sites/default/files/2025-11/Order%20No%20202-25-9.pdf
125	IURC AB Brown CT Order	IURC Order, Cause No. 45664, June 28, 2022	https://iurc.portal.in.gov/entity/sharepoint/documentlocation/1b5e5448-13f7-ec11-bb3b-001dd80095d7/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=ord_45564_062822%20.pdf
126	IURC 2025 CenterPoint Rate Order	IURC Order, Cause No. 45990, Feb. 3, 2025	https://iurc.portal.in.gov/entity/sharepoint/documentlocation/4355f179-6be2-ef11-8eea-001dd8067cf7/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=ord_45990_020325.pdf
127	Chrissy Behme Testimony	Direct Testimony of Chrissy M. Behme on behalf of CenterPoint Energy Indiana South,	https://iurc.portal.in.gov/entity/sharepoint/documentlocation/63d5d9a2-4594-ee11-8178-001dd8065be9/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=45990_CEI%20South_E

No.	Exhibit Name	Document Name	URL
		Cause No. 45990, Dec. 5, 2023	x%20%20-%20Behme%20(PUBLIC) 120523.pdf
128	[Omitted.]		
129	Energy Innovation Report	Eric G. Gimon, Senior Fellow, Energy Innovation, <i>Dodging the Firm Fixation for Data Centers and the Grid</i> (Nov. 2025)	https://energyinnovation.org/wp-content/uploads/Dodging-the-Firm-Fixation-for-Data-Centers-and-the-Grid.pdf
130	NERC Emergency Operations	N. Am. Elec. Reliab. Corp., EOP-011-4 Emergency Operations (last visited Jan. 8, 2026)	https://www.nerc.com/globalassets/standards/reliability-standards/eop/eop-011-4.pdf
131	Eddystone November Order	DOE Order No. 202-25-10 (Nov. 25, 2025)	https://www.energy.gov/sites/default/files/2025-11/Order%20No.%20202-25-10.pdf
132	NIPSCO Rate Case Discovery Responses	NIPSCO Responses to Indiana Office of the Utility Consumer Counselor's Ninth Set of Data Requests in IURC Cause No. 46120, Nov. 4, 2024	
133	Department Press Release on Centralia Order	U.S. Dep't of Energy, Energy Secretary Ensures Washington Coal Plant Remains Open to Ensure Affordable, Reliable and Secure Power Heading into Winter(Dec. 17, 2025)	https://www.energy.gov/articles/energy-secretary-ensures-washington-coal-plant-remains-open-ensure-affordable-reliable-and

No.	Exhibit Name	Document Name	URL
134	MISO Manual on Resource Adequacy	MISO, BPM-011-r31, <i>Resource Adequacy Business Practices Manual</i> (Feb. 21, 2025)	https://www.misoenergy.org/legal/rules-manuals-and-agreements/business-practice-manuals/
135	Holtec News Release	Holtec Int'l, <i>Holtec Receives Coveted "Tier 1 First Mover Award" from the USDOE to Accelerate Deployment of its Dual-Unit SMR-300 Plant at the Company's Palisades Energy Site</i> (Dec. 2, 2025)	https://holtecinternational.com/hh-40-24/
136	Utility Dive Article on Palisades Plant	Meris Lutz, UtilityDive, <i>Palisades Becomes First Decommissioned US Nuclear Plant to Reach 'Operations' Status</i> (Aug. 28, 2025)	https://www.utilitydive.com/news/palisades-nuclear-plant-holtec-nrc-operations/758845/
137	R Street Institute Commentary: <i>DOE "Zombies" Are Eating Competitive Power Markets</i>	Michael Giberson, Senior Fellow, R Street Institute, <i>Low-Energy Fridays: DOE "Zombies" Are Eating Competitive Power Markets</i> (Nov. 13, 2025)	https://www.rstreet.org/commentary/low-energy-fridays-doe-zombies-are-eating-competitive-power-markets/
138	MISO Fall 2025 Operations Report	Bd. of Directors Mkts. Committee, MISO, <i>Operations Report</i> (Dec. 9, 2025)	https://cdn.misoenergy.org/20251209%20Markets%20Committee%20of%20the%20BOD%20Item%2006%20MISO%20Operations%20Report730265.pdf
139	Report of the Nat'l Energy Pol'y Dev. Grp	<i>Reliable, Affordable, and Environmentally Sound Energy for America's Future: Report of the National Energy Policy Development Group</i> (May 2001)	https://www.nrc.gov/docs/ml0428/ml042800056.pdf

No.	Exhibit Name	Document Name	URL
140	MISO ERAS December Release	MISO, <i>MISO Announces Second Cycle of ERAS Projects</i> (Dec. 1, 2025)	https://www.misoenergy.org/meet-miso/media-center/2025---news-releases/miso-announces-second-cycle-of-eras-projects
141	[Omitted.]		
142	Energy Reliability and Resilience	U.S. Dep't of Energy, Energy Reliability and Resilience (webpage as of Oct. 21, 2025)	https://web.archive.org/web/20251021071021/https://www.energy.gov/eere/energy-reliability-and-resilience
143	NERC 2025–2026 Winter Reliability Assessment	NERC, <i>2025–2026 Summer Reliability Assessment</i> (Nov. 18 2025)	https://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf
144	[Omitted.]		
145	NERC Email	Email from NERC Communications Announcements to Rachel Sherrard et al. Re: Announcement NERC 2025-2026 Winter Reliability Assessment Rising Demand, Evolving Resources Continue to Challenge Winter Grid Reliability (Nov. 18, 2025 at 2:02:44 PM EST)	
146	[Omitted.]		

No.	Exhibit Name	Document Name	URL
147	Schahfer 2024 Groundwater Monitoring Report	Northern Indiana Public Service Company LLC, R.M. Schahfer Generating Station Waste Disposal Area 2024 Annual Groundwater Monitoring and Corrective Action Report	https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/ccr/r.m.-schahfer/r.m.-schahfer-generating-station-groundwater-monitoring-and-corrective-action/2025-rm-schahfer-generating-station-waste-disposal-area-annual-groundwater-monitoring-and-corrective-action-report.pdf?sfvrsn=1fc2fa51_3
148	Culley 2024 Groundwater Monitoring Report	Southern Indiana Gas and Electric Company Annual Groundwater Monitoring and Corrective Action Report, East Ash Pond, F.B. Culley Generating Station, January 2025	https://www.centerpointenergy.com/en-us/Documents/CCR-Reporting/Culley-Station-Groundwater-Monitoring/Culley_East_Ash_Pond_Annual_GroundWater_Report_2025.pdf
149	New York Times Article on Trump's Coal Plant Policy	Claire Brown and Brad Plumer, New York Times, <i>Trump Wants to Halt Almost All Coal Plant Shutdowns. It Could Get Messy</i> (Jan. 16, 2026)	https://www.nytimes.com/2026/01/16/climate/trump-coal-plants.html
150	May Campbell Order	DOE Order No. 202-25-3 (May 23, 2025)	https://www.energy.gov/sites/default/files/2025-05/Midcontinent%20Independent%20System%20Operator%20%28MISO%29%20202%28c%29%20Order_1.pdf
151	August Campbell Order	DOE Order No. 202-25-7, August 20,, 2025	https://www.energy.gov/sites/default/files/2025-08/MISO%20Order%20No.%20202-25-7.pdf
152	CenterPoint Rate Case Discovery Responses	IURC Cause No. 45990, CenterPoint Energy Indiana South Responses to the Indiana Office of	

No.	Exhibit Name	Document Name	URL
		the Utility Consumer Counselor's Twenty-Sixth Set of Data Requests	
153	Wayne Games 2018 Testimony	IURC Cause No. 45052, Public Rebuttal Testimony of Wayne D. Games on behalf of Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc., Sep. 10, 2018	https://iurc.portal.in.gov/entity/sharepoint/documentlocation/e4ded2b4-c5b5-e811-8144-1458d04ef938/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=45052%20VectrenSouth%20PublicExhibit4RRebuttalTestimonyWayneGames%20091018.pdf
154	EPA COBRA Schahfer Retirement Analysis	U.S. Environmental Protection Agency, CO-Benefits Risk Assessment (COBRA) for nationwide benefit based on reduction of annual emissions from Schahfer 17 and 18	
155	EPA COBRA Culley Retirement Analysis	U.S. Environmental Protection Agency, CO-Benefits Risk Assessment (COBRA) for nationwide benefit based on reduction of annual emissions from Culley 2	
156	CenterPoint Cost Allocation Complaint	Southern Indiana Gas and Electric Company, Complaint Requesting Fast Track Processing, FERC Docket No. EL26-38-000, Jan. 5, 2026	https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20260105-5189
157	MISO Comments to FERC	Answer of the Midcontinent Independent System Operator, Inc., FERC	https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20260120-5226&optimized=false&sid=07e217b3-76d9-4e6a-9a2b-99ee7f2229d4

No.	Exhibit Name	Document Name	URL
		Docket No. EL26-36-000, Jan. 20, 2026	
158	March Schahfer Order	U.S. Department of Energy's March 23, 2026 Emergency Order No. 202-26-19	https://www.energy.gov/documents/doe-order-no-202-26-19-schahfer
159	March Culley Order	U.S. Department of Energy's March 23, 2026 Emergency Order No. 202-26-20	https://www.energy.gov/documents/doe-order-no-202-26-20-culley
160	Department Order No. 202- 26-01	U.S. Department of Energy's January 24, 2026 Emergency Order No. 202-26-01	https://www.energy.gov/documents/order-no-202-26-01-ercot
161	Department Order No. 202- 26-01A	U.S. Department of Energy's January 25, 2026 Amended Emergency Order No. 202-26-01a	https://www.energy.gov/documents/amended-order-no-202-26-01a
162	Department Order No. 202- 26-03	U.S. Department of Energy's January 25, 2026 Emergency Order No. 202-26-03	https://www.energy.gov/documents/order-no-202-26-03-iso-ne
163	DOE Order No. 202-22-2 Amendment No. 1	U.S. Department of Energy's September 8, 2022 Emergency Order No. 202-22-2 Amendment No. 1	https://www.energy.gov/sites/default/files/2022-09/Amendment%20No.%201%20to%20Order%20202-22-2%20sb%20A_S3%20Hogan.pdf
164	Starfield Email to Hoffman	Email from Lawrence Starfield, EPA to Patricia Hoffman, DOE Re: DOE section 202(c) order (Sept. 11, 2017)	https://www.energy.gov/sites/default/files/2017/09/f36/2017-9-11%20EPA%20consultation%20renewal.pdf

No.	Exhibit Name	Document Name	URL
165	February 2026 Campbell Order	U.S. Department of Energy's February 17, 2026 Emergency Order No. 202-26-16	https://www.energy.gov/documents/order-no-202-26-16-campbell
166	Grid Strategies LTRA Review	Adria E. Brooks et. al., <i>Review of NERC's 2025 Long-Term Reliability Assessment</i> , Grid Strategies (Mar. 5, 2026)	https://gridstrategiesllc.com/wp-content/uploads/FINAL-2025-LTRA-Review.pdf
167	DOE Order No. 202-22-1 Amendment No. 2	U.S. Department of Energy's September 8, 2022 Emergency Order No. 202-22-1 Amendment No. 2	https://www.energy.gov/sites/default/files/2022-09/Amendment%20%20to%20Order%20202-22-1%20FINAL%209.8.2022%20sb%20A%20S3%20Hogan.pdf
168	PIOs' January Rehearing Request	Motion to Intervene and Request for Rehearing and Stay of Public Interest Organizations, Department of Energy Order Nos. 202-25-12, 202-25-13 (Jan. 22, 2026)	https://www.energy.gov/documents/motion-intervene-and-request-rehearing-and-stay-sierra-club-citizens-action-coalition
169	CenterPoint Letter to USDOE	Letter from CenterPoint Energy to United States Department of Energy dated Feb. 17, 2026	
170	MISO 2026–2027 Planning Auction Timeline	Appendix K – Resource Adequacy Timeline for activities for the Planning Year 2026-2027	https://cdn.misoenergy.org/PY%2026-27%20RA%20Timeline720494.pdf
171	MISO ERAS March Release	"MISO accelerates resource additions with third ERAS cycle" (Mar. 9, 2026)	https://www.misoenergy.org/meet-miso/media-center/2026---news-releases/miso-accelerates-resource-additions-with-third-eras-cycle

No.	Exhibit Name	Document Name	URL
172	ERAS Interconnection Requests	ERAS Interconnection Requests as of March 24, 2026	https://cdn.misoenergy.org/ERAS%20Interconnection%20Requests718481.pdf?v=20250925100448
173	Konidena April Declaration	Declaration of Rao Konidena (Apr. 17, 2026) (including attachment)	
174	Saffran Q4 2025 Outage Testimony	Direct Testimony of David Saffran on behalf of Northern Indiana Public Service Company LLC, IURC Cause No. 38706 FAC 150, Feb. 16, 2026	https://iurc.portal.in.gov/entity/sharepoint/documentlocation/2cec3529-6e0b-f111-8406-001dd80babc6/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=38706FAC150_NIPSCO_Petitioners%20Exhibit%204%20(Saffran)_02162026.pdf
175	Wagner February Testimony	Direct Testimony of John A. Wagner on behalf of Northern Indiana Public Service Company LLC, IURC Cause No. 38706 FAC 150, Feb. 16, 2026	https://iurc.portal.in.gov/entity/sharepoint/documentlocation/209c4c11-6e0b-f111-8406-001dd80babc6/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=38706FAC150_NIPSCO_Petitioners%20Exhibit%203%20(Wagner)_02162026.pdf
176	MISO 2026–2027 CIL/CEL Results	MISO Planning Year 2026–2027 Capacity Import Limit / Capacity Export Limit Results (Oct. 30, 2025)	https://cdn.misoenergy.org/20251030%20LOLEWG%20Item%20004%20PY%202026-2027%20CIL_CEL%20Results724589.pdf
177	NERC January 2026 LTRA	Long-Term Reliability Assessment, January 2026, North American Electric Reliability Corporation	https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf
178	Curran Testimony	Statement of Jennifer Curran, Senior Vice President for Planning and Operations,	https://democratsenergycommerce.house.gov/sites/evo-subsites/democrats-energycommerce.house.gov

No.	Exhibit Name	Document Name	URL
		Midcontinent Independent System Operator)	
179	RTO Insider March 2026 Article	MISO: NERC to Dial Down RTO's Risk Level; Members Create Large Load Working Group	https://www.rtoinsider.com/128949-miso-nerc-will-lower-risk-level-stakeholders-create-large-load-working-group
180	IURC March 2026 Public Meeting	Excerpt in .MP4 format of video recording of IURC March 2026 Investigative Inquiry on Energy Affordability (Mar. 24, 2026), beginning at 3:45:19 timestamp	https://www.youtube.com/watch?v=uXEwNQdi3r0
181	MISO January Filing	Answer of the Midcontinent Independent System Operator, Inc., FERC Docket No. EL26-38-000 (Jan. 26, 2026)	https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20260126-5150&optimized=false&sid=17118e9c-5237-458d-b087-880602d58476
182	2026 DOE 202(c) Orders Webpage	U.S. Department of Energy Office of Cybersecurity, Energy Security, and Emergency Response, 2026 Section 202(c) Orders Webpage (last accessed April 22, 2026)	https://www.energy.gov/ceser/2026-doe-202c-orders
183	MISO January Operations Report	MISO Monthly Operations Report, January 2026	https://cdn.misoenergy.org/202601%20Market%20and%20Operations%20Report742938.pdf

No.	Exhibit Name	Document Name	URL
184A	Schahfer Landfill 2025 Groundwater Monitoring Report, Part 1	September 2025 Semi- Annual Groundwater Monitoring Report, Schahfer RWS I Landfill (Nov. 10, 2025), pages 1– 194	https://ecm.idem.in.gov/cs/idcplg?IdcService=GET_FILE&dID=83889189&dDocName=83893231&Rendition=web&allowInterrupt=1&noSaveAs=1
184B	Schahfer Landfill 2025 Groundwater Monitoring Report, Part 2	September 2025 Semi- Annual Groundwater Monitoring Report, Schahfer RWS I Landfill (Nov. 10, 2025), pages 195–299	<i>(Same as Exhibit 184A)</i>

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Midcontinent	)	Order No. 202-26-29
Independent System Operator and	)	
Northern Indiana Public Service	)	
Company LLC	)	

Federal Power Act Section 202(c)	)	
Emergency Order: Midcontinent	)	Order No. 202-26-30
Independent System Operator and	)	
CenterPoint Energy Indiana South	)	

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 195
NIPSCO Summer 2026 Reliability Presentation



2026 Summer Reliability Forum

May 19, 2026



OUR VISION IS TO BE A
PREMIER, INNOVATIVE & TRUSTED
ENERGY PARTNER



NIPSCO Presenters



Vince Parisi
President and COO



Rufus Jackson
SVP Electric
Operations



Karl Stanley
VP Supply &
Optimization



Phil Winter
Sr Director
Power Delivery



Rockey Pollard
Director Station
Chem & Env

NIPSCO Profile

IMPROVING THE LIVES OF APPROXIMATELY 1.4 MILLION CUSTOMERS ACROSS NORTHERN INDIANA

ELECTRIC

- ~500,000 electric customers
- Second-largest electric distribution company in Indiana
- 3,985.25 MW generating capacity
 - 2 coal generation facilities
 - 2 CT's
 - 1 CCGT
 - 2 hydro electric generation facilities
 - 8 owned renewable generation facilities in service
- Transmission system has voltages from 69,000 to 765,000 volts, consisting of approximately 3,000 circuit miles
 - Interconnected with 8 neighboring electric utilities
 - Operate 66 transmission and 250 distribution substations
 - Own ~311,300 poles

HEADQUARTERED IN
MERRILLVILLE, IN

3,100
EMPLOYEES

NATURAL GAS

- 900,000 natural gas customers
- Largest natural gas distribution company in Indiana
- ~18,000 miles of distribution main pipeline
- ~710 miles of transmission main pipeline
- Two on-system storage facilities

**NIPSCO'S SYSTEM MUST BE BUILT TO
DELIVER FOR CUSTOMERS DURING
SUSTAINED PERIODS OF EXTREME
TEMPERATURES AND WEATHER CONDITIONS**

Changes Since Last Summer Reliability Forum

DOE 202(c) Order

- On December 23, 2025, the Secretary of Energy issued DOE Order No. 202-25-12 (Order) which directed NIPSCO and MISO to "take all measures necessary" to ensure that Schahfer Units 17 and 18 continue to operate.
- Under Section 202(c) of the Federal Power Act, DOE's Orders are in effect for a maximum of 90 days; subsequent 90-day Orders may be issued for the same units.
- On March 23, 2025, DOE extended the Order for another 90 days.

Post-Order Operations of Units 17 and 18

- At the time of the Order, Unit 17 was derated while Unit 18 was in a MISO Forced Outage.
- Pursuant to the Order, NIPSCO offered Unit 17 into the market up to its derated availability until it went into a planned outage March 1.
- NIPSCO has begun repairs to return Units 17 and 18 to full operations pursuant to the Order.

NIPSCO's FERC Complaint Case Against MISO

- On December 29, 2025, NIPSCO filed a Complaint at FERC against MISO asserting that the MISO Tariff does not contain a Tariff Schedule for recovery of the costs associated with repairing and operating Units 17 and 18.
- As part of the Complaint, NIPSCO proposed a Tariff Schedule 56 that would uplift these costs to all customers on a pro-rata basis in the MISO Northern and Central Zones.
- On March 19, 2026, FERC issued Order granting complaint against MISO, requiring MISO to make a compliance filing adding NIPSCO's Schedule to the MISO Tariff.

After FERC Issues Order on Complaint Case

- NIPSCO is currently preparing its FERC case for recovery of the costs associated with Units 17 and 18 for filing.



GenCo Model to Support Data Center Development

NIPSCO Generation (GenCo)

- **Separate utility company created to build, own, and operate major investments**
 - These costs are excluded from the costs to serve NIPSCO's other electric customers
- Isolates major capital investments to protect from rate increases and end-of-contract risks
- Existing customers will not pay for any of the capacity / generation or load-side investments needed to serve data centers now or in the future
- Investments made by data center customers help build a more resilient and reliable grid, and additional generation will provide benefits to all customers



Structure will Drive Customer Savings

- **GenCo cost savings total approximately \$1.4 billion for existing customers through Alphabet and Amazon collaboration**
- Residential customers will receive a credit each month, which will begin in 2027
- Additional contracts will drive additional savings to electric customers

Creation of Customer Fund

- NIPSCO and GenCo will make \$17+ million of contributions to a "customer fund" over the next 15 years, fully funded by shareholders
- 50% will be for the local communities where generation and data center development occur
- 50% will be passed back to all NIPSCO electric customers as part of the customer credit discussed above

Generation Portfolio

NEW GENERATION FACILITIES*	INSTALLED CAPACITY (MW)	COUNTY	IN SERVICE
ROSEWATER WIND	102 MW	WHITE	2020 COMPLETE
JORDAN CREEK WIND	400 MW	BENTON & WARREN	2020 COMPLETE
INDIANA CROSSROADS WIND	302 MW	WHITE	2021 COMPLETE
DUNNS BRIDGE SOLAR I	265 MW	JASPER	2022 COMPLETE
INDIANA CROSSROADS SOLAR	200 MW	WHITE	2023 COMPLETE
INDIANA CROSSROADS II WIND	200 MW	WHITE	2023 COMPLETE
CAVALRY SOLAR	200 MW + 45 MW BATTERY	WHITE	2024 COMPLETE
GREEN RIVER SOLAR	200 MW	BRECKINRIDGE & MEADE (KY)	2025 COMPLETE
DUNNS BRIDGE SOLAR II	435 MW + 56.25 MW BATTERY	JASPER	2025 COMPLETE
GIBSON SOLAR	200 MW	GIBSON	2025 COMPLETE
FAIRBANKS SOLAR	250 MW	SULLIVAN	2025 COMPLETE
APPLESEED SOLAR	200 MW	CASS	2025 COMPLETE
CARPENTER WIND	200 MW	JASPER	2025 COMPLETE
TEMPLETON WIND	200 MW	BENTON	2027 PRE-CONSTRUCTION
GAS PEAKING RESOURCE	400 MW	JASPER	2027 PRE-CONSTRUCTION

GENERATION FACILITIES	INSTALLED CAPACITY (MW)	FUEL	COUNTY
MICHIGAN CITY RETIRING 2028	455 MW	COAL	LAPORTE
R.M. SCHAHFER OPERATING UNDER 202C ORDER	722 MW + 155 MW	COAL + NATURAL GAS	JASPER
SUGAR CREEK	563 MW	NATURAL GAS	VIGO
NORWAY HYDRO	7.2 MW	WATER	WHITE
OAKDALE HYDRO	9.2 MW	WATER	CARROLL



Changes in Generation Fleet

Since last year's Summer Reliability Forum NIPSCO added:

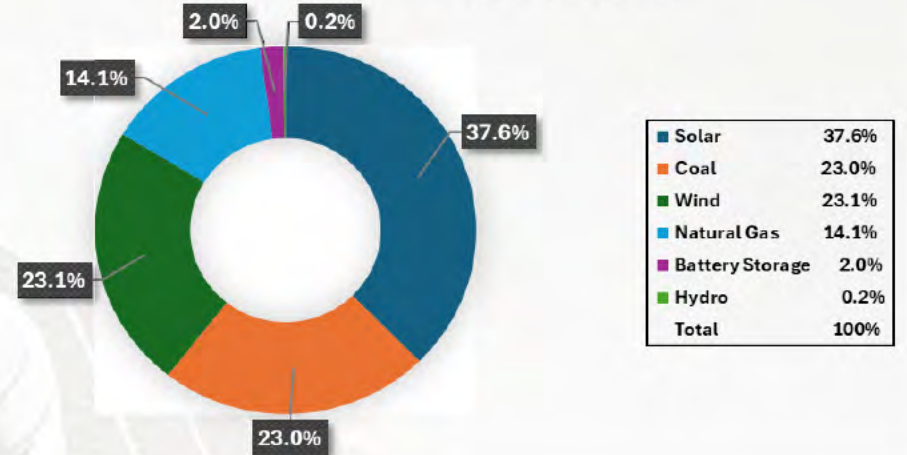
- Carpenter Wind (PPA): 200 MW
- Appleseed Solar (PPA): 200 MW

The biggest change since 2021 to NIPSCO's fleet is the addition of:

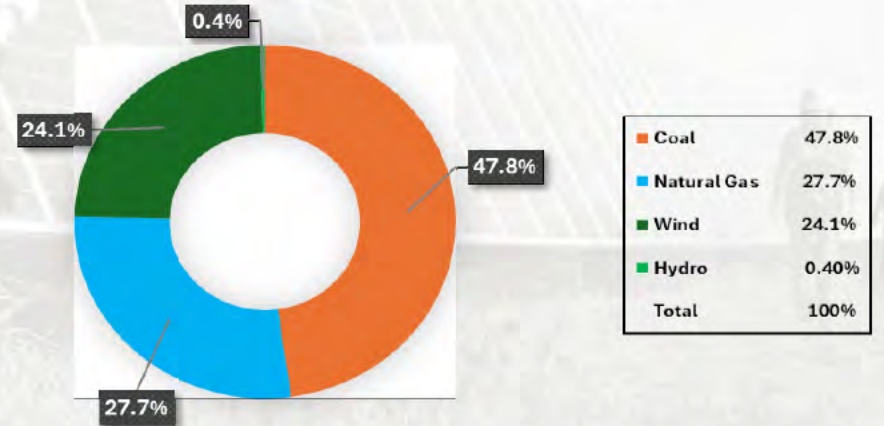
- 3 Wind Farms
- 8 Solar Farms
- 2 Battery Storage Units



2026 NIPSCO Generation Mix



2021 NIPSCO Generation Mix



Capital Investments

Safety & Reliability

- AMI
- Distribution Automation

Renewables

- Wind, Solar, & Battery Storage Projects
- Associated Transmission Projects

Maintenance

- Pole Life Extension Program
- Power Transformer Replacements

Growth

- Circuit Reconductors
- New Substations

Electric	2021	2022	2023	2024	2025	TOTAL
Safety & Reliability	5.5	38.1	108.5	155.3	136.5	443.9
MISO	0.0	0.0	0.0	27.6	72.9	100.5
Renewables	63.3	362.0	997.1	617.4	1,260.7	3,300.5
Public Improvement	45.4	4.9	9.6	7.4	9.8	77.1
Maintenance	320.1	375.9	462.4	391.5	291.1	1,841.0
Growth	47.7	67.5	98.8	119.3	291.5	624.8
TOTAL	482.0	848.4	1,676.5	1,318.5	2,062.4	6,387.8

Reliability Improvements Since Last Summer Reliability Forum

Distribution Automation & System Modernization

- This program identifies circuits that need additional sectionalizing capabilities or that serve emergency services.
- Deploying reclosers and upgrading modern protective relaying reduces the number of customers affected during outages by detecting and isolating faults on the circuit.
- This program evaluates areas with 3-phase trunk lines and long single-phase taps that need additional sectionalizing devices to reduce the number of unprotected areas and minimize the number of customers affected by outages.
- In 2025, there were 30 three-phase reclosers deployed. Areas were prioritized based upon reliability performance and population density.

Circuit Performance Improvement (CPI) & Cable Replacement Programs

- These programs target the worst performing overhead and underground circuits and taps.
- CPI has improved the reliability for customers experiencing the poorest reliability in 2024-2025.
- In 2025, 42 miles of unjacketed underground cable was replaced mitigating over 80% of the interruptions on the addressed circuits.

Pole Inspection Program & Life Extension Program

- This program includes the inspection and treatment of all poles on a 10-year cycle.
- In 2025, there were 1,530 poles replaced or reinforced based upon inspection results.
- Replacing poles no longer meeting strength requirements helps to prevent failures during severe weather.

Changes in Resource Adequacy Since 2021

- MISO introduced a **Seasonal Resource Adequacy Construct** for the Planning Year 2023/2024. Previously Resource Adequacy had been measured on an annual basis, while the Seasonal Resource Adequacy Construct breaks the planning year into four seasons, with each season having a separate planning resource margin and separate asset capacity accreditation values.
- This move to a seasonal construct makes the accreditation for each resource more fluid from season to season, as well as year after year, which could result in the need for more or less resources during select times of the year.
- In 2024, MISO announced that they would be switching their planning resource modeling framework to a **Direct Loss of Load** (DLOL) methodology starting in Planning Year 2028/2029.
- This new methodology will look at not only peak hours during each season but will include “tight” hours whereby the amount of resources available might not be sufficient to meet the load.
- **This new methodology is expected to capture the changing behavior of the portfolio as more renewables and battery energy storage systems penetrate the resource portfolio.**



Resource Adequacy Position

- MISO's Planning Resource Auction (PRA) results were released on April 28, 2026. There are no operational and resource concerns for the Planning Year 2026-2027.
- NIPSCO participated in MISO's PRA with **surplus capacity of 896.4 MW in the summer season and 737.1 in the fall season.**
- NIPSCO was party to several successful seasonal transactions and believes that the current planning year will be easier to navigate as participants become more comfortable with the process, capacity market design questions are satisfied, and seasonal markets become more robust.
- There is a greater emphasis on unit availability, performance, and outages by MISO seasonal construct that could drive the need for unexpected replacement capacity during seasons.
- The demand response program does not factor into NIPSCO's jurisdictional demand. However, it is used by Rate 631 large industrial customers to balance their resource adequacy requirement.

Unit Availability & Spring Maintenance Outages

MCGS Unit 12 is currently online and Full Load capable

- Unit 12 was in a successful Planned Outage from 2/27/26 through 3/21/26
- Significant work was done on unit cleaning for the summer run as well as cooling tower repairs

RMSGGS Units 16A and 16B have been offline in Forced Outage since 3rd quarter of 2025

- Both units are undergoing a full turbine and compressor overhaul
- Expect to have 16A available 5/27/26 and 16B on 7/10/26

RMSGGS Unit 17 has been in a Planned Maintenance Outage since 2/28/26

- Significant boiler and turbine work underway to support DOE 202c
- Turbine work is critical path with a tentative return end of Q3; inspections are ongoing

RMSGGS Unit 18 has been offline in Forced Outage since July of 2025

- Significant boiler and turbine work underway to support DOE 202c
- Turbine work is critical path with a tentative return end of Q3; inspections are ongoing

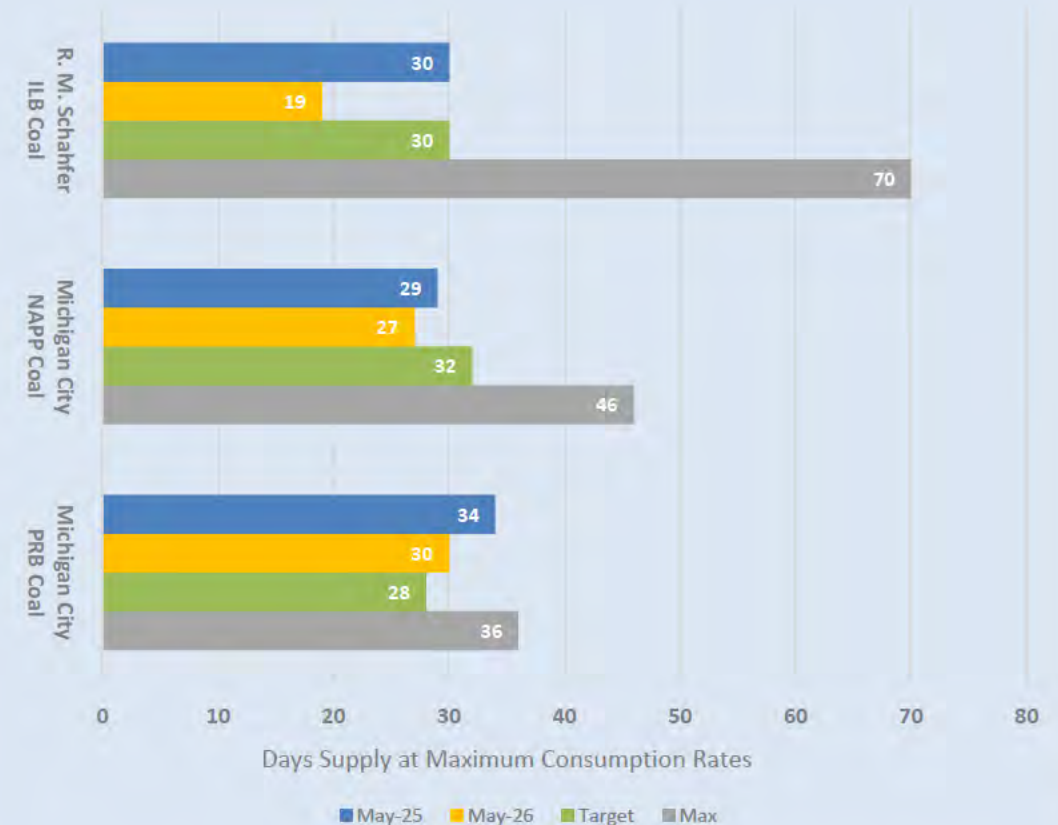
2026 NIPSCO Generation Outage Season: February through July						
					Unit 17	Unit 18
July	Week 5					
	Week 4					
	Week 3					
	Week 2			Unit 16B		
	Week 1					
June	Week 4					
	Week 3					
	Week 2					
	Week 1		Unit 16A			
May	Week 4					
	Week 3					
	Week 2					
	Week 1					
April	Week 4					
	Week 3					
	Week 2					
	Week 1					
March	Week 4	Unit 12				
	Week 3					
	Week 2					
	Week 1					
February	Week 4					
	Week 3					
	Week 2					
	Week 1					

Fuel Availability

Coal Supply

- NIPSCO's coal inventory balances the costs associated with maintaining coal inventory with reliability to ensure units are available to supply energy during periods of high demand, extreme weather, fuel transportation disruptions, or mine production problems.
- NIPSCO has maintained inventory levels near target levels despite variable consumption rates. Class I railroad performance has been good over the last three years which reduces delivery variability and ultimately helps control inventory levels.
- NIPSCO typically builds inventory ahead of winter and summer peaks and is projecting **Michigan City inventories will be near targets at the start of summer.**
- **Schahfer's inventory is being increased during 2026** after it was reduced to near zero prior to receiving the DOE 202c order to extend operations. NIPSCO has proposed to uplift Schahfer's ongoing operating costs to all customers on a pro-rata basis in the MISO Northern and Central Zones.
- **NIPSCO has firm coal supply contracts, coal transportation agreements, and an adequate fleet of railcars to ensure reliable coal supply for all electric generation needs.**

NIPSCO ELECTRIC GENERATION COAL INVENTORY



Fuel Availability

Natural Gas Supply

- **NIPSCO has firm natural gas to ensure reliable natural gas supply for all electric generation needs.**
- The Customer will see the benefits of 100% generation availability for gas and coal due to our firm fuel contracts.
- NIPSCO's electric operations procure natural gas for electric generation. NIPSCO holds 70,000 Dth/d of firm transportation directly on Midwestern Gas Transmission Interstate pipeline. This contract ensures fuel supply reliability and resource adequacy planning.



Winter Storm Fern

Generator Winter Performance

- Nine periods of MISO cold weather alerts, including Winter Storm Fern, which was from January 23 to January 27
- Winter customer peak of 1,946.5 MW occurred on Friday, January 23
- Overall winter operational performance December 1 to February 28 was over target at 19.5% EFOR
- Schahfer Unit 17 ran continuously during the month of January 2026, and generated over 38,000 MWH of energy into MISO during Winter Storm Fern

Lessons Learned: Winter Storm Fern

- First MISO emergency event for BESS
 - Modifying charge/discharge decisions for future
- Modifying future gas pre-emergency procurement decisions



Summer Bill Projections

NIPSCO SUMMER BILL PROJECTIONS

MONTH	PROJECTED USAGE (KWH)	2026 (PROJECTED RATES)
MAY	572.0	\$135.21
JUNE	791.9	\$181.57
JULY	988.9	\$223.17
AUGUST	911.4	\$216.73
SEPTEMBER	626.9	\$154.71
TOTAL	3,891.1	\$911.39

WHAT ARE WE DOING PROGRAMS, OFFERINGS & INITIATIVES

- **Energy Assistance**
 - Federal/State
 - Company-Funded
- **Energy Efficiency**
 - Low-Income Audits
 - Tips & Calculators
- **Billing & Payment Offerings**
 - Levelized Billing Plan
 - DependABill
 - Payment Plans
- **Bill Explainers**
- **Billing Worksheets**
- **Infographics**
- **Videos**
- **Website Enhancements**
- **Paid Social Media Outreach**
- **Customer Newsletters**
- **Mailers – December 2025**
- **Emails**
- **Customer Care Center Events**

The average electric residential bill is projected to be **\$182.28** for the summer season.



NIPSCO residential electric customers should expect their summer cooling bills to be higher this season compared to last year due primarily to base rate increases in 2025 and 2026. These increases are partly offset by lower forecasted tracker costs.

Levelized Billing Plan

Levelized Billing Implementation

- Levelized Billing Plan will be applied to all **LIHEAP approved electric and combo residential customers** July 1.
- All **customers (electric, gas, and combo) currently on Budget Plan** will move to Levelized Billing Plan July 1.
- **Seasonal periods** will run from May through October and November through April, with any adjustments made in May and November.

Customer Communications

- **Web site enhancements** regarding Levelized Billing Plan and reconciliation mechanism
- **Letters to LIHEAP customers** informing them of auto-enroll to Levelized Billing Plan and process for opting out
- **Letter to Budget Plan customers** informing them of move to Levelized Billing Plan and process for opting out
- **Bill inserts**
- **Call Aid** for CSRs

April 1, 2026



Dear NIPSCO Customer,

We know rising energy costs have been difficult for many families, especially during periods of extreme weather. Indiana lawmakers recently passed a new law, **Indiana House Enrolled Act 1002**, which expands the use of a Levelized Billing Plan. A Levelized Billing Plan (formerly NIPSCO's Budget Plan) applies to customers who are eligible for NIPSCO and LIHEAP assistance. You are receiving this letter because you qualify for a Levelized Billing Plan.

The new Levelized Billing Plan provides equal monthly payments during a defined period in which actual energy usage is compared to the usage estimate, and any difference is accounted for. This structure helps eligible customers manage seasonal energy costs and avoid monthly payment spikes.

Key components of the Levelized Billing Plan:

- For customers who qualify for and receive LIHEAP, the Levelized Billing Plan will begin the first monthly billing cycle after June 30, 2026.
- A reconciliation (review) will occur two times each year to reflect your seasonal energy use from May through October and November through April, with any adjustments to your monthly bill based on your estimated average energy use for that current season; your actual energy use is compared with the actual amount billed under the Budget Plan and will be adjusted up or down for any difference.
- You will continue to have the option to opt out at any time without penalty if you choose.
- Your total bill will still depend on how much energy you use and broader market conditions.

Because you have received LIHEAP assistance, you will be automatically enrolled in the Levelized Billing Plan beginning the first billing cycle after June 30, 2026. If you do not wish to be enrolled in the Levelized Billing Plan, you can opt out by one of the following ways:

- Complete the simple online form at [NIPSCO.com/LevelizedBilling](https://www.nipSCO.com/LevelizedBilling)
- Email us at LevelizedBilling@nisource.com
- Return the attached document in the prepaid envelope provided
- Call us at 1-800-464-7726

Our Commitment to You

NIPSCO is working to implement these changes thoughtfully and transparently. We're updating our billing systems, improving customer communications, and continuing to connect customers with assistance programs and payment options when help is needed.

If you have questions about the Levelized Billing Plan, payment assistance, or how this law may affect you, we're here to help.

Thank you for being a NIPSCO customer and providing safe, reliable energy.

Sincerely,

NIPSCO Customer Service



MY ACCOUNT

SERVICES

OUTAGES

SAFETY

BILLS & PAYMENTS

WAYS TO SAVE

Sign In / Register

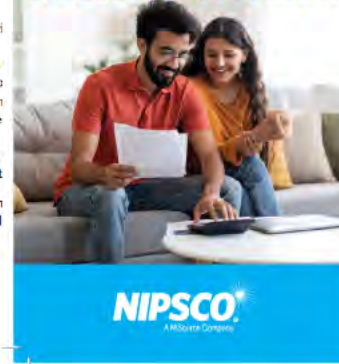
HELP

NIPSCO IMPLEMENTS LEVELIZED BILLING

New Indiana law aimed at improving electric bill predictability for customers

Indiana House Enrolled Act 1002 is a new state law designed to help improve electric bill stability for customers who may benefit most from more predictable monthly payments. The law updates how electric utilities offer Levelized Billing Plans, which provide equal monthly payments and include periodic reviews of actual energy use.

Please note: Not all customers are affected by this change.



New Name for a Familiar Plan: **Levelized Billing**

We know higher energy costs have made it harder for many families—especially during very cold or very hot weather. The Indiana General Assembly recently passed a new law to help make energy bills more predictable. We're writing to explain an update to NIPSCO's Budget Plan and what it means for you.

What's changing

Indiana House Enrolled Act 1002 updated how utilities offer level monthly billing. Because of this law, **NIPSCO's Budget Plan will now be called Levelized Billing.**

Key Plan Updates

- **The Levelized Billing Plan is a 12-month plan for all customers.** Already on a 12-month Budget Plan? You'll stay enrolled—only the name is changing.
- **Currently on an 8-month Budget Plan?** Starting with billing cycles that begin after June 30, 2026, your account will move to 12-month Levelized Billing Plan.
- **No action is needed from you at this time.**

Customer Assistance for Residential Energy Program

The NIPSCO Customer Assistance for Residential Energy Program (CARE) is implemented through participating local agencies in each county under the Indiana Housing and Community Development Authority (IHCD).



SUMMER CARE PROGRAM

- The Commission approved NIPSCO's summer assistance program in NIPSCO's most recent rate case. Similar to the Gas Winter Care Program, eligible LIHEAP Customers are automatically enrolled in Summer Care, which will provide a discount on usage from June to September.
- NIPSCO funded the program with a **\$1.5M of shareholder contribution** and has developed an option for customers to contribute \$0.25/meter per month to increase the program funding.
- The program will begin applying discounts in June 2026.
- **To comply with HEA 1002**, in July 2026, NIPSCO will begin including a monthly notice on customers bills informing them that NIPSCO offers a low-income customer assistance program.

SUMMER DISCONNECT MORATORIUM

- NIPSCO voluntarily delays disconnection for nonpayment of electric service if temperatures are above 90° on the scheduled day of disconnection or are forecasted to be above 90° the following two days.
- **NIPSCO will also comply with HEA 1002** and delay disconnection for nonpayment of electric service for LIHEAP eligible customers on any day, not earlier than 48 hours in advance, a heat index of at least 95° for a county or part of a county is forecasted.



QUESTIONS?



APPENDIX

Biggest Changes Since Five Years Ago

Safety and Reliability	Investments that improve the safety of electric and gas systems and modernization of electric and gas assets to improve on demand deliverability to customers i.e.: AMI – Improves visibility for our system and customers through remotely read meters. Leads to improved outage response times and load forecasting. Distribution Automation – Reduces impact of electric outages. Upgrade of Marktown Substation which supports several large industrial customers. Upgrade of 600# gas loop to improve the reliability of gas transmission and distribution systems. Replacement of Gary Bare Steel distribution system.
MISO	Midcontinent Independent System Operator required investments i.e.: This segment of work includes 345kV and 765kV system upgrades and MISO LRTP Tranche 1 investments.
Renewables	Expanding renewable energy generation within NIPSCO i.e.: This category includes Wind, Solar and Battery Storage.
Public Improvement	Investments required to support mandatory relocation of gas and electric assets to support municipalities and DOT. i.e.: Relocation of poles and lines or underground gas assets to support roundabout construction, bridge expansions, city sewer line installs, etc.
Maintenance	Investments to replace failed assets or assets nearing, at, or past end of life expectations i.e.: Pole Life Extension Program – Replace end of life structures, preventing outages, while also extending the life of those still in good condition. Power Transformer Replacements – Replace poor condition transformers with new modern equivalents, preventing large source outages while also improving asset health data. Underground cable replacement program to address aging distribution assets. Gas transmission and distribution mains including pipe, pipe fittings, pressure control fittings, steel services, valves, casings, and cathodic protection equipment, as well as improvements to aging stations.
Growth	Investments targeted to support increased demand and ability to deliver utility services to customers i.e.: Circuit Reconductors – Upgrade conductors to accommodate new loads and improve system reliability through new outage restoration opportunities. New Substations – Build new electric substations and circuits to serve new loads and create system capacity for reliability. Installation of new gas distribution stations and pipeline including increased volumetric delivery. New gas service provided to over 34,000 rural customers and over 44,000 non-rural customers.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Midcontinent	)	Order No. 202-26-29
Independent System Operator and	)	
Northern Indiana Public Service	)	
Company LLC	)	

Federal Power Act Section 202(c)	)	
Emergency Order: Midcontinent	)	Order No. 202-26-30
Independent System Operator and	)	
CenterPoint Energy Indiana South	)	

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 196
NIPSCO 2026 Planning Reserve Margin Report

STATE OF INDIANA

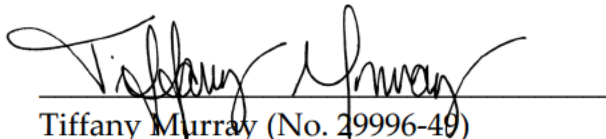
INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF NORTHERN INDIANA)
PUBLIC SERVICE COMPANY LLC FOR)
DETERMINATION THAT CERTAIN)
INFORMATION CONTAINED IN ITS REPORT) CAUSE NO. 46402
TO BE SUBMITTED TO THE COMMISSION)
PURSUANT TO IND. CODE § 8-1-8.5-13 IS)
CONFIDENTIAL AND EXEMPT FROM)
DISCLOSURE PURSUANT TO 170 IAC 1-1.1-4,)
IND. CODE § 8-1-2-29 AND IND. CODE § 5-14-3-4.)

PETITIONER'S SUBMISSION OF REDACTED REPORTS

Northern Indiana Public Service Company LLC, by counsel, respectfully submits
the attached redacted reports filed pursuant to Ind. Code § 8-1-8.5-13.

Respectfully submitted,



Tiffany Murray (No. 29996-49)

NiSource Corporate Service – Legal

150 W. Market Street, Suite 600

Indianapolis, Indiana 46204

Phone: 317.649-6424

Fax: 317.684.4918

Email: tiffanymurray@nisource.com

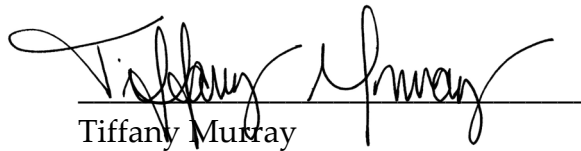
Attorney for Petitioner

Northern Indiana Public Service Company LLC

CERTIFICATE OF SERVICE

The undersigned hereby certifies that the foregoing was served via email transmission upon Abby Gray and Carol Sparks Drake, Indiana Office of Utility Consumer Counselor, 115 W. Washington Street, Suite 1500 South, Indianapolis, Indiana 46204 (agray@oucc.in.gov, cadrake@oucc.in.gov, infomgt@oucc.in.gov).

Dated this 1st day of May, 2026.



Tiffany Murray

IC 8-1-8.5-13(i) Reporting Form - Planning Resource Year 1 (2026 to 2027)

Indiana Utility Regulatory Commission

Add rows below as necessary. For resources located outside of Zone 6, please provide a description of the deliverability arrangements.
For demand response resources, please provide a description of each program.

Owned Resource 8-1-8.5-13(i)(1) definition	IC Nameplate capacity	ICAP (MW) Nameplate capacity	Summer UCAP (MW) IC 8-1-8.5-13(f) definition	Fall UCAP (MW) IC 8-1-8.5-13(f) definition	Winter UCAP (MW) IC 8-1-8.5-13(g) definition	Spring UCAP (MW) IC 8-1-8.5-13(f) definition	Location: RTO interconnection zone	Fuel Source	Additional Comments
CIN.SUCRKGT1		175	166.5	155.7	123.8	181.2	Zone 6	Gas	This is one combined asset.
CIN.SUCRKGT2		175	170.5	159.7	147.6	183.1	Zone 6	Gas	
CIN.SUCRKST1		228	218.6	196.1	172.1	227.3	Zone 6	Waste Heat	
NIPS.MICHCP12		469	309	254	213.4	291	Zone 6	Coal	
NIPS.NORWAPNOR		4	1.4	0.7	2.2	3.3	Zone 6	Water	
NIPS.OAKDAPPAK		6	1.3	0	2.1	4.2	Zone 6	Water	
NIPS.ROSEWRWF		100.1	16.7	11	27.2	20.6	Zone 6	Wind	This is a tax equity joint venture w/ NIPSCO as controlling member
NIPS.INCROSWF		300.1	49.1	30.2	75.1	58.8	Zone 6	Wind	This is a tax equity joint venture w/ NIPSCO as controlling member
NIPS.SCHAH16A		78	47.2	53.7	58.4	73	Zone 6	Gas	
NIPS.SCHAH16B		77	56.4	52	68.1	63.9	Zone 6	Gas	
NIPS.DUNNBR1SF		265	178.4	120.7	3.3	145	Zone 6	Solar	This is a tax equity joint venture w/ NIPSCO as controlling member
NIPS.INCRMLSP		200	129.1	88.7	1.9	110.9	Zone 6	Solar	This is a tax equity joint venture w/ NIPSCO as controlling member.
NIPS.DUNNBR2SF		435	263.3	217.5	21.8	247.1	Zone 6	Solar	
NIPS.DUNNBR2BS		56.25	54.9	53.8	53.1	56.3	Zone 6	Battery	
CIN.NIPS.FRBK		250	158.2	125	12.5	125	Zone 6	Solar	
CIN.NIPS.GBSNS		200	100	100	10	100	Zone 6	Solar	
NIPS.CAVALRYSF		200	134.4	86.3	2.8	119.2	Zone 6	Solar	
NIPS.CAVALRYBS		45	44.4	45	44.8	31.2	Zone 6	Battery	

Contracted Resource IC 8-1-8.5-13(i)(2) definition	ICAP (MW) Nameplate capacity	Summer UCAP (MW) IC 8-1-8.5-13(f) definition	Fall UCAP (MW) IC 8-1-8.5-13(f) definition	Winter UCAP (MW) IC 8-1-8.5-13(g) definition	Spring UCAP (MW) 8.5-13(f) definition	IC 8-1-8.5-13(f) definition	Location: RTO interconnection zone	Fuel Source	Additional Comments
									Capacity from external resource zone
									Capacity from external resource zone
									Capacity from external resource zone
									Capacity from external resource zone (allocations to Alphabet)

Demand Response Resource IC 8-1-8.5-13(i)(3) definition	Summer UCAP (MW) IC 8-1-8.5-13(f) definition	Fall UCAP (MW) IC 8-1-8.5-13(g) definition	Winter UCAP (MW) IC 8-1-8.5-13(g) definition	Spring UCAP (MW) IC 8-1-8.5-13(g) definition	Additional Comments
					Please see below, where NIPSCO has broken this out to account for Rate 831 Tier 2 and 3.

NIPSCO 631 Tier 2 & 3 Customers Contracted Resource	Summer UCAP (ZRC)	Fall UCAP (ZRC)	Winter UCAP (ZRC)	Spring UCAP (ZRC)	Additional Comments
A	0	0	0	0	Load Purchase Capacity (ZRC) by Customer
B	0	0	0	0	Load Purchase Capacity (ZRC)
C	172.4	150.7	179.9	199.2	Load Purchase Capacity (ZRC) by Customer
D	0	0	0	0	Load Purchase Capacity (ZRC) by Customer
E	0	0	0	0	Load Purchase Capacity (ZRC) by Customer
F	0	0	0	0	Load Purchase Capacity (ZRC) by Customer
G	0	0	0	0	Load Purchase Capacity (ZRC) by Customer

NIPSCO 631 Tier 2 & 3 Customers Load Modifying Resource	Summer Registered As LMR @ MISO (ZRC) X (1+PRM) X (1+TL)) (MW	Fall Registered As LMR @ MISO (ZRC) (MW X (1+PRM) X (1+TL))	Winter Registered As LMR @ MISO (ZRC) (MW X (1+PRM) X (1+TL))	Spring Registered As LMR @ MISO (ZRC) (MW X (1+PRM) X (1+TL))	Additional Comments
A	217.8	193.2	201.5	220.3	Registered as LMR @ MISO by NIPSCO
B	0.0	0.0	0.0	0.0	Registered as LMR @ MISO by NIPSCO
C	0.0	0.0	0.0	0.0	Registered as LMR @ MISO by NIPSCO
D	79.7	81.9	87.2	88.0	Registered as LMR @ MISO by NIPSCO
E	0.0	0.0	0.0	0.0	Registered as LMR @ MISO by NIPSCO
F	75.8	83.5	96.4	96.9	Registered as LMR @ MISO by NIPSCO
G	107.4	193.4	187.0	226.5	Registered as LMR @ MISO by NIPSCO

		This minus Rate 631 Tier 2 & 3 Customers	This with Rate 631 Tier 2 & 3 Customers	Additional Comments
RTO established Planning Reserve Margin requirement <i>(see IC 8-1-8.5-13 (i)(4))</i>	Summer Demand ___ MWx(1+ % PRM ___) ___MW	2596	3436.2	w/ TL of 2.5% PRMR of 7.9%

NIPSCO has performed this calculation without Rate 631 Tier 2 and 3 customers (column D) and with those customers (column E)

Fall Demand ___ MWx(1+ % PRM ___) ___MW	This minus Rate 631 Tier 2 & 3 Customers	This with Rate 631 Tier 2 & 3 Customers	Additional Comments
	2408.1	3279.8	w/ TL of 1.6% PRMR of 11.6%

Winter Demand ___ MWx(1+ % PRM ___) ___MW	This minus Rate 631 Tier 2 & 3 Customers	This with Rate 631 Tier 2 & 3 Customers	Additional Comments
	2049.1	2974.8	w/ TL of 2.1% PRMR of 18.9%

Spring Demand ___ MWx(1+ % PRM ___) ___MW	This minus Rate 631 Tier 2 & 3 Customers	This with Rate 631 Tier 2 & 3 Customers	Additional Comments
	2704.8	3499.0	w/ TL of 2.7% PRMR of 23.4%

Please describe any other federal reliability requirement:	
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Reliability Adequacy Metrics <i>(defined in IC 8-1-8.5-13(e))</i>			
Summer RA Metric <i>IC 8-1-8.5-13(e)(1)</i>	Fall RA Metric <i>IC 8-1-8.5-13(e)(2)</i>	Winter RA Metric <i>IC 8-1-8.5-13(e)(2)</i>	Spring RA Metric <i>IC 8-1-8.5-13(e)(2)</i>
Summer UCAP/PRM Requirement ___%	Fall UCAP/PRM Requirement ___%	Winter UCAP/PRM Requirement ___%	Spring UCAP/PRM Requirement ___%

NIPSCO has performed this calculation (below) without Rate 631 Tier 2 and 3 customers (columns B and C) and with those customers (column D and E)

This minus Rate 631 Tier 2 & 3 Customers				This with Rate 631 Tier 2 & 3 Customers			
Summer UCAP	Fall UCAP	Winter UCAP	Spring UCAP	Summer UCAP	Fall UCAP	Winter UCAP	Spring UCAP
Summer RA Metric	Fall RA Metric	Winter RA Metric	Spring RA Metric	Summer RA Metric	Fall RA Metric	Winter RA Metric	Spring RA Metric

IC 8-1-8.5-13(i) Reporting Form - Planning Resource Year 2 (2027 to 2028)

Indiana Utility Regulatory Commission

Add rows below as necessary. For resources located outside of Zone 6, please provide a description of the deliverability arrangements.
For demand response resources, please provide a description of each program.

Owned Resource <i>IC 8-1-8.5-13(i)(1) definition</i>	IC	ICAP (MW) <i>Nameplate capacity</i>	Summer UCAP (MW) <i>IC 8-1-8.5-13(f) definition</i>	Fall UCAP (MW) <i>IC 8-1-8.5-13(f) definition</i>	Winter UCAP (MW) <i>IC 8-1-8.5-13(g) definition</i>	Spring UCAP (MW) <i>IC 8-1-8.5-13(f) definition</i>	Location: <i>RTO interconnection zone</i>	Fuel Source	Additional Comments
CIN.SUCRKG1		175	163.7	153.7	147.8	175.2	Zone 6	Gas	This is one combined asset.
CIN.SUCRKG2		175	167.7	157.7	178.5	176.2	Zone 6	Gas	
CIN.SUCRKST1		228	218.6	196.1	172.1	227.3	Zone 6	Waste Heat	
NIPS.MICHCP12		469	309	254	213.4	291	Zone 6	Coal	
NIPS.NORWAPNOR		4	1.4	0.7	2.2	3.3	Zone 6	Water	
NIPS.OAKDAPOAK		6	1.3	0	2.1	4.2	Zone 6	Water	
NIPS.ROSEWRWF		100.1	16.7	11	27.2	20.6	Zone 6	Wind	This is a tax equity joint venture w/ NIPSCO as controlling member
NIPS.INCROSWF		300.1	49.1	30.2	75.1	58.8	Zone 6	Wind	This is a tax equity joint venture w/ NIPSCO as controlling member
NIPS.SCHAH16A		78	47.2	53.7	58.4	73	Zone 6	Gas	
NIPS.SCHAH16B		77	56.4	52	68.1	63.9	Zone 6	Gas	
NIPS.DUNNB1SF		265	178.4	120.7	3.3	145	Zone 6	Solar	This is a tax equity joint venture w/ NIPSCO as controlling member.
NIPS.INCRM1SP		200	129.1	88.7	1.9	110.9	Zone 6	Solar	This is a tax equity joint venture w/ NIPSCO as controlling member.
NIPS.DUNNB2SF		435	263.3	217.5	21.8	247.1	Zone 6	Solar	
NIPS.DUNNB2BS		56.25	54.9	53.8	53.1	56.3	Zone 6	Battery	
CIN.NIPS.FRBNK		250	158.2	125	12.5	125	Zone 6	Solar	
CIN.NIPS.GBSNS		200	100	100	10	100	Zone 6	Solar	
NIPS.CAVALRYSF		200	134.4	86.3	2.8	119.2	Zone 6	Solar	
NIPS.CAVALRYBS		45	44.4	45	44.8	31.2	Zone 6	Battery	
Peaker		408			325.3	380.3	Zone 6	Gas	
Mitchell BESS		300				285	Zone 6	Battery	Alphabet/Amazon

Contracted Resource <i>IC 8-1-8.5-13(i)(2) definition</i>	ICAP (MW) <i>Nameplate capacity</i>	Summer UCAP (MW) <i>IC 8-1-8.5-13(f) definition</i>	Fall UCAP (MW) <i>IC 8-1-8.5-13(f) definition</i>	Winter UCAP (MW) <i>IC 8-1-8.5-13(g) definition</i>	Spring UCAP (MW) <i>IC 8-1-8.5-13(f) definition</i>	IC 8-1-8.5-13(i)(2) definition	Location: <i>RTO interconnection zone</i>	Fuel Source	Additional Comments
									Capacity from external resource zone
									Capacity from external resource zone (allocations to Alphabet/Amazon)
									Alphabet
									Identified Resource, Market Capacity Purchase opportunity

Demand Response Resource <i>IC 8-1-8.5-13(i)(3) definition</i>	Summer UCAP (MW) <i>IC 8-1-8.5-13(f) definition</i>	Fall UCAP (MW) <i>IC 8-1-8.5-13(g) definition</i>	Winter UCAP (MW) <i>IC 8-1-8.5-13(g) definition</i>	Spring UCAP (MW) <i>IC 8-1-8.5-13(g) definition</i>	Additional Comments
					Please see below, where NIPSCO has broken this out to account for Rate 631 Tier 2 and 3.

NIPSCO 631 Tier 2 & 3 Customers Contracted Resource	Summer UCAP (ZRC)	Fall UCAP (ZRC)	Winter UCAP (ZRC)	Spring UCAP (ZRC)	Additional Comments
A	0	0	0	0	Load Purchase Capacity (ZRC)
B	0	0	0	0	Load Purchase Capacity (ZRC) by Customer
C	172.4	150.7	179.9	199.2	Load Purchase Capacity (ZRC) by Customer
D	0	0	0	0	Load Purchase Capacity (ZRC) by Customer
E	0	0	0	0	Load Purchase Capacity (ZRC) by Customer
F	0	0	0	0	Load Purchase Capacity (ZRC) by Customer
G	0	0	0	0	Load Purchase Capacity (ZRC) by Customer

NIPSCO 631 Tier 2 & 3 Customers Load Modifying Resource	Summer Registered As LMR @ MISO (ZRC) $(MW \times (1+PRM) \times (1+TL))$	Fall Registered As LMR @ MISO (ZRC) $(MW \times (1+PRM) \times (1+TL))$	Winter Registered As LMR @ MISO (ZRC) $(MW \times (1+PRM) \times (1+TL))$	Spring Registered As LMR @ MISO (ZRC) $(MW \times (1+PRM) \times (1+TL))$	Additional Comments
A	217.8	193.2	201.5	220.3	Registered as LMR @ MISO by NIPSCO
B	0.0	0.0	0.0	0.0	Registered as LMR @ MISO by NIPSCO
C	0.0	0.0	0.0	0.0	Registered as LMR @ MISO by NIPSCO
D	79.7	81.9	87.2	88.0	Registered as LMR @ MISO by NIPSCO
E	0.0	0.0	0.0	0.0	Registered as LMR @ MISO by NIPSCO
F	75.8	83.5	96.4	96.9	Registered as LMR @ MISO by NIPSCO
G	107.4	193.4	187.0	226.5	Registered as LMR @ MISO by NIPSCO

		This minus Rate 631 Tier 2 & 3 Customers	This with Rate 631 Tier 2 & 3 Customers	Additional Comments
RTO established Planning Reserve Margin requirement <i>(see IC 8-1-8.5-13 (j)(4))</i>	Summer Demand ____ MWx(1+ % PRM ____) ____MW	2795.5	3635.7	w/ TL of 2.5% PRMR of 7.9%

NIPSCO has performed this calculation without Rate 631 Tier 2 and 3 customers (column D) and with those customers (column E)

Fall Demand ____ MWx(1+ % PRM ____) ____MW	This minus Rate 631 Tier 2 & 3 Customers	This with Rate 631 Tier 2 & 3 Customers	Additional Comments
	2922.8	3794.6	w/ TL of 1.6% PRMR of 11.6%

Winter Demand ____ MWx(1+ % PRM ____) ____MW	This minus Rate 631 Tier 2 & 3 Customers	This with Rate 631 Tier 2 & 3 Customers	Additional Comments
	2827.9	3753.6	w/ TL of 2.1% PRMR of 18.9%

Spring Demand ____ MWx(1+ % PRM ____) ____MW	This minus Rate 631 Tier 2 & 3 Customers	This with Rate 631 Tier 2 & 3 Customers	Additional Comments
	3577.2	4563.8	w/ TL of 2.7% PRMR of 23.4%

Please describe any other federal reliability requirement:	
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Reliability Adequacy Metrics <i>[defined in IC 8-1-8.5-13(e)]</i>			
Summer RA Metric <i>IC 8-1-8.5-13(e)(1)</i>	Fall RA Metric <i>IC 8-1-8.5-13(e)(2)</i>	Winter RA Metric <i>IC 8-1-8.5-13(e)(2)</i>	Spring RA Metric <i>IC 8-1-8.5-13(e)(2)</i>
Summer UCAP/PRM Requirement ____%	Fall UCAP/PRM Requirement ____%	Winter UCAP/PRM Requirement ____%	Spring UCAP/PRM Requirement ____%

NIPSCO has performed this calculation (below) without Rate 631 Tier 2 and 3 customers (columns B and C) and with those customers (column D and E)

This minus Rate 631 Tier 2 & 3 Customers				This with Rate 631 Tier 2 & 3 Customers			
Summer UCAP	Fall UCAP	Winter UCAP	Spring UCAP	Summer UCAP	Fall UCAP	Winter UCAP	Spring UCAP
Summer RA Metric	Fall RA Metric	Winter RA Metric	Spring RA Metric	Summer RA Metric	Fall RA Metric	Winter RA Metric	Spring RA Metric

IC 8-1-8.5-13(i) Reporting Form - Planning Resource Year 3 (2028 to 2029)

Indiana Utility Regulatory Commission

Add rows below as necessary. For resources located outside of Zone 6, please provide a description of the deliverability arrangements.
For demand response resources, please provide a description of each program.

Owned Resource <i>8-1-8.5-13(i)(1) definition</i>	IC <i>Nameplate capacity</i>	ICAP (MW) <i>Nameplate capacity</i>	Summer UCAP (MW) <i>IC 8-1-8.5-13(f) definition</i>	Fall UCAP (MW) <i>IC 8-1-8.5-13(f) definition</i>	Winter UCAP (MW) <i>IC 8-1-8.5-13(g) definition</i>	Spring UCAP (MW) <i>IC 8-1-8.5-13(j) definition</i>	Location: <i>RTO interconnection zone</i>	Fuel Source	Additional Comments
CIN.SUCRKG1	175	175	163.7	153.7	147.8	175.2	Zone 6	Gas	This is one combined asset.
CIN.SUCRKG2	175	175	167.7	157.7	178.5	176.2	Zone 6	Gas	
CIN.SUCRKST1	228	228	218.6	196.1	172.1	227.3	Zone 6	Waste Heat	
NIPS.MICHCP12	469	469	309	254			Zone 6	Coal	
NIPS.NORWAPNOR	4	4	1.4	0.7	2.2	3.3	Zone 6	Water	
NIPS.OAKDAPOAK	6	6	1.3	0	2.1	4.2	Zone 6	Water	
NIPS.ROSEWRWF	100.1	100.1	8.6	14.4	23	15	Zone 6	Wind	This is a tax equity joint venture w/ NIPSCO as controlling member
NIPS.INCROSWF	300.1	300.1	25.8	43.2	69	45	Zone 6	Wind	This is a tax equity joint venture w/ NIPSCO as controlling member
NIPS.SCHAH16A	78	78	47.2	53.7			Zone 6	Gas	
NIPS.SCHAH16B	77	77	56.4	52			Zone 6	Gas	
NIPS.DUNNBR1SF	265	265	63.6	36	23.3	37.6	Zone 6	Solar	This is a tax equity joint venture w/ NIPSCO as controlling member.
NIPS.INCRM1SP	200	200	48	27.2	17.6	28.4	Zone 6	Solar	This is a tax equity joint venture w/ NIPSCO as controlling member.
NIPS.DUNNBR2SF	435	435	104.4	59.2	38.3	61.8	Zone 6	Solar	
NIPS.DUNNBR2BS	56.25	56.25	44.4	53.2	50.5	53.7	Zone 6	Battery	
CIN.NIPS.FRB1NK	250	250	60	34	22	35.5	Zone 6	Solar	
CIN.NIPS.GBSNS	200	200	48	27.2	17.6	28.4	Zone 6	Solar	
NIPS.CAVALRYSF	200	200	48	27.2	17.6	28.4	Zone 6	Solar	
NIPS.CAVALRYBS	45	45	35.6	42.6	40.4	42.9	Zone 6	Battery	
Peaker	408	408	334.7	325.1	315.4	302.1	Zone 6	Gas	
Peaker CT1	385	385				246.4	Zone 6	Gas	Amazon
Peaker CT2	385	385				246.4	Zone 6	Gas	Amazon
MITCHELL BESS	500	500	395	473	449	477	Zone 6	Battery	Amazon & Alphabet
Tipton BESS	167	167	131.9	158.0	150.0	159.3	Zone 6	Battery	Alphabet
Templeton Wind	200	200	17.2	28.8	46	30	Zone 6	Wind	

Contracted Resource <i>IC 8-1-8.5-13(i)(2) definition</i>	ICAP (MW) <i>Nameplate capacity</i>	Summer UCAP (MW) <i>IC 8-1-8.5-13(f)</i>	Fall UCAP (MW) <i>IC 8-1-8.5-13(f)</i>	Winter UCAP (MW) <i>IC 8-1-8.5-13(g)</i>	Spring UCAP (MW) <i>IC 8-1-8.5-13(j) definition</i>	IC 8-1-8.5-13(j) definition	Location: <i>RTO interconnection zone</i>	Fuel Source	Additional Comments
									Capacity from external resource zone
									Capacity from external resource zone - (allocations to Amazon/Alphabet)
									Alphabet
									Identified Resource, Market Capacity Purchase opportunity

Demand Response Resource <i>IC 8-1-8.5-13(i)(3) definition</i>	Summer UCAP (MW) <i>IC 8-1-8.5-13(f) definition</i>	Fall UCAP (MW) <i>IC 8-1-8.5-13(g) definition</i>	Winter UCAP (MW) <i>IC 8-1-8.5-13(g) definition</i>	Spring UCAP (MW) <i>IC 8-1-8.5-13(g) definition</i>	Additional Comments
					Please see below, where NIPSCO has broken this out to account for Rate 631 Tier 2 and 3.

NIPSCO 631 Tier 2 & 3 Customers Contracted Resource	Summer UCAP (ZRC)	Fall UCAP (ZRC)	Winter UCAP (ZRC)	Spring UCAP (ZRC)	Additional Comments
A	0	0	0	0	Load Purchase Capacity (ZRC)
B	0	0	0	0	Load Purchase Capacity (ZRC) by Customer
C	172.4	150.7	179.9	199.2	Load Purchase Capacity (ZRC) by Customer
D	0	0	0	0	Load Purchase Capacity (ZRC) by Customer
E	0	0	0	0	Load Purchase Capacity (ZRC) by Customer
F	0	0	0	0	Load Purchase Capacity (ZRC) by Customer
G	0	0	0	0	Load Purchase Capacity (ZRC) by Customer

NIPSCO 631 Tier 2 & 3 Customers Load Modifying Resource	Summer Registered As LMR @ MISO (ZRC) $(MW \times (1+PRM) \times (1+TL))$	Fall Registered As LMR @ MISO (ZRC) $(MW \times (1+PRM) \times (1+TL))$	Winter Registered As LMR @ MISO (ZRC) $(MW \times (1+PRM) \times (1+TL))$	Spring Registered As LMR @ MISO (ZRC) $(MW \times (1+PRM) \times (1+TL))$	Additional Comments
A	217.8	193.2	201.5	220.3	Registered as LMR @ MISO by NIPSCO
B	0.0	0.0	0.0	0.0	Registered as LMR @ MISO by NIPSCO
C	0.0	0.0	0.0	0.0	Registered as LMR @ MISO by NIPSCO
D	79.7	81.9	87.2	88.0	Registered as LMR @ MISO by NIPSCO
E	0.0	0.0	0.0	0.0	Registered as LMR @ MISO by NIPSCO
F	75.8	83.5	96.4	96.9	Registered as LMR @ MISO by NIPSCO
G	107.4	193.4	187.0	226.5	Registered as LMR @ MISO by NIPSCO

		This minus Rate 631 Tier 2 & 3 Customers	This with Rate 631 Tier 2 & 3 Customers	Additional Comments
RTO established Planning Reserve Margin requirement <i>(see IC 8-1-8.5-13 (i)(4))</i>	Summer Demand ____ MWx(1+ % PRM ____) ____ MW	3546.1	4343.7	w/ TL of 2.5% PRMR of 2.4%

NIPSCO has performed
this calculation without
Rate 631 Tier 2 and 3
customers (column D)
and with those
customers (column E)

		This minus Rate 631 Tier 2 & 3 Customers	This with Rate 631 Tier 2 & 3 Customers	Additional Comments
	Fall Demand ____ MWx(1+ % PRM ____) ____ MW	3703.4	4549.5	w/ TL of 1.6% PRMR of 6%

		This minus Rate 631 Tier 2 & 3 Customers	This with Rate 631 Tier 2 & 3 Customers	Additional Comments
	Winter Demand ____ MWx(1+ % PRM ____) ____ MW	3449.1	4271.3	w/ TL of 2.1% PRMR of 6%

		This minus Rate 631 Tier 2 & 3 Customers	This with Rate 631 Tier 2 & 3 Customers	Additional Comments
	Spring Demand ____ MWx(1+ % PRM ____) ____ MW	3747.7	4560.7	w/ TL of 2.7% PRMR of 1%

Please describe any other federal reliability requirement:	
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Reliability Adequacy Metrics <i>(defined in IC 8-1-8.5-13(e))</i>			
Summer RA Metric <i>IC 8-1-8.5-13(e)(1)</i>	Fall RA Metric <i>IC 8-1-8.5-13(e)(2)</i>	Winter RA Metric <i>IC 8-1-8.5-13(e)(2)</i>	Spring RA Metric <i>IC 8-1-8.5-13(e)(2)</i>
Summer UCAP/PRM Requirement ____%	Fall UCAP/PRM Requirement ____%	Winter UCAP/PRM Requirement ____%	Spring UCAP/PRM Requirement ____%

NIPSCO has performed this
calculation (below) without
Rate 631 Tier 2 and 3
customers (columns B and C)
and with those customers
(column D and E)

This minus Rate 631 Tier 2 & 3 Customers				This with Rate 631 Tier 2 & 3 Customers			
Summer UCAP	Fall UCAP	Winter UCAP	Spring UCAP	Summer UCAP	Fall UCAP	Winter UCAP	Spring UCAP
Summer RA Metric	Fall RA Metric	Winter RA Metric	Spring RA Metric	Summer RA Metric	Fall RA Metric	Winter RA Metric	Spring RA Metric

IC § 8-1-8.5-13(n)(2) requires the following:

(2) With respect to a report submitted to the commission after December 31, 2025, the amount of generating resource capacity or energy, or both, that the public utility plans to retire and that is owned and operated by the public utility and used to provide retail electric service in Indiana, including the:

(A) capacity;

(B) location;

(C) fuel source; and

(D) planned retirement date;

for each electric generating facility. The public utility must include information as to whether the planned retirement is required in order to comply with environmental laws, regulations, or court orders, including consent decrees, that are or will be in effect at the time of the planned retirement. In addition, the public utility must provide its economic rationale for the planned retirement, including anticipated ratepayer impacts, and information concerning the public utility's plan or plans with respect to the amount of replacement capacity identified to provide approximately the same accredited capacity within the appropriate regional transmission organization as the amount of capacity of the facility to be retired.

Schahfer Units 16A & 16B

(A) Capacity: 78MW + 77 MW

(B) Location: 2723E 1500N Wheatfield, IN 46392

(C) Fuel source: Gas

(D) Planned retirement date: December 2028

The preferred portfolios in NIPSCO's 2018, 2021, and 2024 IRPs reflect retirement of Schahfer Units 16A & 16B shortly after Schafer's coal units were set to retire. The economic rationale for the retirement of Schahfer Units 16A & 16B is the age of the units and their inefficient heat rates. No specific environmental laws, regulations, court orders, or consent decrees are driving the retirement of Schahfer Units 16A & 16B; the age of the units and their heat rate are the primary drivers of retirement. This capacity is intended to be replaced by a new (more efficient) gas peaker project that would be 40-50% more efficient in its heat rate. The anticipated ratepayer impact of the new gas peaker at Schahfer was identified in the proceeding in which the project was granted a CPCN, Cause No. 45967, and the project is subject to ongoing review in NIPSCO's GCT tracker.

IC § 8-1-8.5-13(n)(2) requires the following:

(2) With respect to a report submitted to the commission after December 31, 2025, the amount of generating resource capacity or energy, or both, that the public utility plans to retire and that is owned and operated by the public utility and used to provide retail electric service in Indiana, including the:

(A) capacity;

(B) location;

(C) fuel source; and

(D) planned retirement date;

for each electric generating facility. The public utility must include information as to whether the planned retirement is required in order to comply with environmental laws, regulations, or court orders, including consent decrees, that are or will be in effect at the time of the planned retirement. In addition, the public utility must provide its economic rationale for the planned retirement, including anticipated ratepayer impacts, and information concerning the public utility's plan or plans with respect to the amount of replacement capacity identified to provide approximately the same accredited capacity within the appropriate regional transmission organization as the amount of capacity of the facility to be retired.

Michigan City Unit 12

(A) Capacity : 469MW

(B) Location: 101 Wabash St, Michigan City, IN 46360

(C) Fuel source: Coal

(D) Planned retirement date: December 2028

The preferred portfolios in NIPSCO's 2018, 2021, and 2024 IRPs reflect retirement of Michigan City Unit 12 and replacement of that capacity with a combination of wind, solar, energy storage, and gas peaking resources. The preferred portfolios in NIPSCO's 2021 IRP and 2024 IRPs reflected a 2028 retirement year. As stated in those IRPs, the economic rationale for this retirement decision was impacted by:

1) Production Tax Credits and Investment Tax Credits (now either repealed or restricted by the federal One Big Beautiful Bill enacted in 2025)

2) Expectation of EPA Green House Gas rule 111b, which was expected to require 90% carbon capture for coal units to be in effect by 2030 and would have added significant compliance costs for continued operation. In June 2025, EPA proposed a rule change in which the agency withdraws its prior conclusions that carbon capture and sequestration/storage and natural gas co-firing are "adequately demonstrated," commercially available and cost-effective systems of emission reduction to reduce GHG emissions.

As of today, the two environmental laws and tax regulations listed above have been repealed/restricted. NIPSCO's 1520 report contains information concerning potential replacement capacity options NIPSCO is exploring to provide approximately the same accredited capacity as the amount of capacity of the facility to be retired. Any anticipated ratepayer impact will be available when the replacement capacity resource is selected.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Midcontinent	)	Order No. 202-26-29
Independent System Operator and	)	
Northern Indiana Public Service	)	
Company LLC	)	

Federal Power Act Section 202(c)	)	
Emergency Order: Midcontinent	)	Order No. 202-26-30
Independent System Operator and	)	
CenterPoint Energy Indiana South	)	

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 197
CenterPoint 2026 Planning Reserve Margin Report

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF SOUTHERN INDIANA GAS AND ELECTRIC COMPANY D/B/A CENTERPOINT ENERGY INDIANA SOUTH (“CEI SOUTH”) FOR DETERMINATION THAT CERTAIN INFORMATION CONTAINED IN ITS REPORT TO BE SUBMITTED TO THE COMMISSION PURSUANT TO IND. CODE § 8-1-8.5-13 AND 170 IAC 4-7-2.3 IS CONFIDENTIAL AND EXEMPT FROM DISCLOSURE PURSUANT TO 170 IAC 1-1.1-4, IND. CODE § 8-1-2-29 AND IND. CODE § 5-14-3-4.

CAUSE NO. 46403

**SUBMISSION OF CENTERPOINT ENERGY INDIANA SOUTH’S
2026 HEA 1520 REPORT**

In accordance with Indiana Code § 8-1-8.5-13 and the Commission’s May 7, 2026 Docket Entry in this Cause, Petitioner Southern Indiana Gas and Electric Company, Inc. d/b/a CenterPoint Energy Indiana South (“CEI South”) hereby provides the public redacted version of its 2026 HEA 1520 Report.

(Signature Page Follows)

DATED: May 7, 2026

Respectfully submitted,
SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
D/B/A CENTERPOINT ENERGY INDIANA SOUTH



Heather A. Watts Atty. No. 35482-82

Jeffery A. Earl Atty. No. 27821-64

Kenneth Thomson, Atty. No. 39526-82

Kelly M. Beyrer, Atty. No. 36322-49

Southern Indiana Gas and Electric Company

d/b/a CenterPoint Energy Indiana South

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CERTIFICATE OF SERVICE

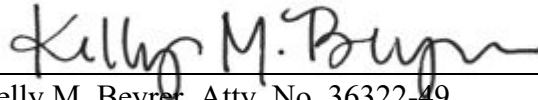
I certify that on May 7, 2026, this document was filed with the Indiana Utility Regulatory Commission using the Commission's electronic filing system and was served electronically on the parties below.

Indiana Office of Utility Consumer Counselor

115 West Washington Street, Suite 1500 South

Indianapolis, IN 46204

infomgt@oucc.in.gov

A handwritten signature in cursive script, reading "Kelly M. Beyrer", written over a horizontal line.

Kelly M. Beyrer, Atty. No. 36322-49

IC 8-1-8.5-13(l) Reporting Form - Planning Resource Year 1 (2026 to 2027)

Indiana Utility Regulatory Commission

Add rows below as necessary. For resources located outside of Zone 6, please provide a description of the deliverability arrangements.
For demand response resources, please provide a description of each program.

Owned Resource <i>IC 8-1-8.5-13(l)(1) definition</i>	ICAP (MW) <i>Nameplate capacity</i>	Summer Accredited Capacity (MW) <i>IC 8-1-8.5-13(k) definition</i>	Fall Accredited Capacity (MW) <i>IC 8-1-8.5-13(d) definition</i>	Winter Accredited Capacity (MW) <i>IC 8-1-8.5-13(l) definition</i>	Spring Accredited Capacity (MW) <i>IC 8-1-8.5-13(j) definition</i>	Location: <i>RTO interconnection zone</i>	Fuel Source	Additional Comments
AB Brown 3	80	67.8	70.1	88	71.7	MISO Zone 6	Gas/Fuel Oil	Primary fuel is natural gas but can operate on fuel oil
AB Brown 4	80	71.1	74.6	85.7	78.3	MISO Zone 6	Gas	-
AB Brown 5	232.3	201.9	208.3	198.2	210.9	MISO Zone 6	Natural Gas	-
AB Brown 6	232.3	153.5	206.3	198.2	208.2	MISO Zone 6	Natural Gas	-
FB Culley 2	90	0	0	0	0	MISO Zone 6	Coal	The current DOE 202c Order expires 6/21/2026; and requires the unit operate as an energy-only resource. Absent an extension of the DOE 202c Order, the MISO-approved suspension of FBC2 will begin on June 22, 2026.
FB Culley 3	270	196.4	206.7	207	230.6	MISO Zone 6	Coal	
OVEC (Ohio Valley Electric Corp.)	32.2	29.3	30.1	30.9	30.9	MISO External Zone 23	Coal	CEI South owns 1.5% share of OVEC's total capacity. OVEC is located in MISO external zone 23, and is interconnected through the transmission provider LGEE (Louisville Gas & Electric) to SIGE with Transmission Service Request reference #4931291.
Troy Solar	50	31.1	24.2	0.7	27.4	MISO Zone 6	Solar	
Posey Solar	191	136.9	95.4	9.5	95.4	MISO Zone 6	Solar	
Oak Hill Solar	2	0	0	0	0	MISO Zone 6	Solar	Located on CEI South distribution system and accounted for in peak load forecast. Not a SAC resource.
Volkman Rd Solar	2	0	0	0	0	MISO Zone 6	Solar	Located on CEI South distribution system and accounted for in peak load forecast. Not a SAC resource.
Volkman Road Battery	1	0	0	0	0	MISO Zone 6	BESS	Located on CEI South distribution system and accounted for in peak load forecast. Not a SAC resource.
Blackfoot Landfill	3.2	0	0	0	0	MISO Zone 6	LFG	Located on CEI South distribution system and accounted for in peak load forecast. Not a SAC resource.

Contracted Resource <i>IC 8-1-8.5-13(l)(2) definition</i>	ICAP (MW) <i>Nameplate capacity</i>	Summer Accredited Capacity (MW) <i>IC 8-1-8.5-13(k) definition</i>	Fall Accredited Capacity (MW) <i>IC 8-1-8.5-13(d) definition</i>	Winter Accredited Capacity (MW) <i>IC 8-1-8.5-13(l) definition</i>	Spring Accredited Capacity (MW) <i>IC 8-1-8.5-13(j) definition</i>	Location: <i>RTO interconnection zone</i>	Fuel Source	Additional Comments
Benton County Wind Farm						MISO Zone 6	Wind	
Fowler Wind Farm						MISO Zone 6	Wind	
Wheatland Solar						MISO Zone 6	Solar	
Galesburg Wind						MISO Zone 4	Wind	
Salt Creek Wind						MISO Zone 3	Wind	
Aggregator						MISO Zone 6	N/A	
Capacity Contracts								
Total Contracted Resources		286	293	291	320			

Demand Response Resource <i>IC 8-1-8.5-13(l)(3) definition</i>	Summer Accredited Capacity (MW) <i>IC 8-1-8.5-13(k) definition</i>	Fall Accredited Capacity (MW) <i>IC 8-1-8.5-13(d) definition</i>	Winter Accredited Capacity (MW) <i>IC 8-1-8.5-13(l) definition</i>	Spring Accredited Capacity (MW) <i>IC 8-1-8.5-13(j) definition</i>	Additional Comments
DR-DLC-Thermostats	10.4	6	0	0	Program utilizes smart thermostats to curtail residential central air conditioner load during hours of system peak demand. This DR is only available in summer months per CEI South tariff

Resource Retirements <i>IC 8-1-8.5-13(i) definition</i>	Summer Accredited Capacity (MW) <i>IC 8-1-8.5-13(k) definition</i>	Fall Accredited Capacity (MW) <i>IC 8-1-8.5-13(d) definition</i>	Winter Accredited Capacity (MW) <i>IC 8-1-8.5-13(l) definition</i>	Spring Accredited Capacity (MW) <i>IC 8-1-8.5-13(j) definition</i>	Additional Comments
N/A					

Refueled Resources <i>IC 8-1-8.5-13(g) definition</i>	Summer Accredited Capacity (MW) <i>IC 8-1-8.5-13(k) definition</i>	Fall Accredited Capacity (MW) <i>IC 8-1-8.5-13(d) definition</i>	Winter Accredited Capacity (MW) <i>IC 8-1-8.5-13(l) definition</i>	Spring Accredited Capacity (MW) <i>IC 8-1-8.5-13(j) definition</i>	Additional Comments
N/A					

RTO established Planning Reserve Margin requirement ¹ <i>(see IC 8-1-8.5-13 (f))</i>	1,106	973.8	915	990.5
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Please describe any other federal reliability requirement:	
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Reliability Adequacy Metrics <i>[defined in IC 8-1-8.5-13(h)]</i>			
Summer RA Metric	Winter RA Metric	Spring RA Metric	Fall RA Metric
107%	125%	121%	129%

1. CEI South PRMR as of March 25, 2026, as provided by MISO, and consistent with the prior 1520 reports

IC 8-1-8.5-13(I) Reporting Form - Planning Resource Year 1 (2027 to 2028)
Indiana Utility Regulatory Commission

Add rows below as necessary. For resources located outside of Zone 6, please provide a description of the deliverability arrangements.
For demand response resources, please provide a description of each program.

Owned Resource <i>IC 8-1-8.5-13(l)(1) definition</i>	ICAP (MW) <i>Nameplate capacity</i>	Summer Accredited Capacity (MW) <i>IC 8-1-8.5-13(k) definition</i>	Fall Accredited Capacity (MW) <i>IC 8-1-8.5-13(d) definition</i>	Winter Accredited Capacity (MW) <i>IC 8-1-8.5-13(l) definition</i>	Spring Accredited Capacity (MW) <i>IC 8-1-8.5-13(j) definition</i>	Location: <i>RTO interconnection zone</i>	Fuel Source	Additional Comments
AB Brown 3	80	67.4	72.1	91.7	75.8	MISO Zone 6	Gas/Fuel Oil	Primary fuel is natural gas but can operate on fuel oil
AB Brown 4	80	70.5	67.3	89.2	80.3	MISO Zone 6	Gas	-
AB Brown 5	232.3	209.1	195.1	183.5	195.1	MISO Zone 6	Natural Gas	-
AB Brown 6	232.3	209.1	195.1	183.5	195.1	MISO Zone 6	Natural Gas	-
FB Culley 3	270	181.4	248.8	231.6	269.6	MISO Zone 6	Coal	-
OVEC (Ohio Valley Electric Corp.)	32.2	29.5	30.4	31.2	30.8	MISO External Zone 23	Coal	CEI South owns 1.5% share of OVEC's total capacity. OVEC is located in MISO external zone 23, and is interconnected through the transmission provider LGEE (Louisville Gas & Electric) to SIGE with Transmission Service Request reference #4931291.
Troy Solar	50	22.3	17.5	12.8	23.4	MISO Zone 6	Solar	
Posey Solar	191	85.0	66.8	48.7	89.2	MISO Zone 6	Solar	
Oak Hill Solar	2	0	0	0	0	MISO Zone 6	Solar	Located on CEI South distribution system and accounted for in peak load forecast. Not a SAC resource.
Volkman Rd Solar	2	0	0	0	0	MISO Zone 6	Solar	Located on CEI South distribution system and accounted for in peak load forecast. Not a SAC resource.
Volkman Road Battery	1	0	0	0	0	MISO Zone 6	BESS	Located on CEI South distribution system and accounted for in peak load forecast. Not a SAC resource.
Blackfoot Landfill	3.2	0	0	0	0	MISO Zone 6	LFG	Located on CEI South distribution system and accounted for in peak load forecast. Not a SAC resource.

Contracted Resource <i>IC 8-1-8.5-13(l)(2) definition</i>	ICAP (MW) <i>Nameplate capacity</i>	Summer Accredited Capacity (MW) <i>IC 8-1-8.5-13(k) definition</i>	Fall Accredited Capacity (MW) <i>IC 8-1-8.5-13(d) definition</i>	Winter Accredited Capacity (MW) <i>IC 8-1-8.5-13(l) definition</i>	Spring Accredited Capacity (MW) <i>IC 8-1-8.5-13(j) definition</i>	Location: <i>RTO interconnection zone</i>	Fuel Source	Additional Comments
Benton County Wind Farm						MISO Zone 6	Wind	
Fowler Wind Farm						MISO Zone 6	Wind	
Wheatland Solar						MISO Zone 6	Solar	
Galesburg Wind						MISO Zone 4	Wind	
Salt Creek Wind						MISO Zone 3	Wind	
Aggregator						MISO Zone 6	N/A	
Capacity Contracts								
Total Contracted Resources		326	353	333	352			

Demand Response Resource <i>IC 8-1-8.5-13(l)(3) definition</i>	Summer Accredited Capacity (MW) <i>IC 8-1-8.5-13(k) definition</i>	Fall Accredited Capacity (MW) <i>IC 8-1-8.5-13(d) definition</i>	Winter Accredited Capacity (MW) <i>IC 8-1-8.5-13(l) definition</i>	Spring Accredited Capacity (MW) <i>IC 8-1-8.5-13(j) definition</i>	Additional Comments
DR-DLC-Thermostats	10.5	6	0	0	

Resource Retirements <i>IC 8-1-8.5-13(i) definition</i>	Summer Accredited Capacity (MW) <i>IC 8-1-8.5-13(k) definition</i>	Fall Accredited Capacity (MW) <i>IC 8-1-8.5-13(d) definition</i>	Winter Accredited Capacity (MW) <i>IC 8-1-8.5-13(l) definition</i>	Spring Accredited Capacity (MW) <i>IC 8-1-8.5-13(j) definition</i>	Additional Comments
N/A					

Refueled Resources <i>IC 8-1-8.5-13(g) definition</i>	Summer Accredited Capacity (MW) <i>IC 8-1-8.5-13(k) definition</i>	Fall Accredited Capacity (MW) <i>IC 8-1-8.5-13(d) definition</i>	Winter Accredited Capacity (MW) <i>IC 8-1-8.5-13(l) definition</i>	Spring Accredited Capacity (MW) <i>IC 8-1-8.5-13(j) definition</i>	Additional Comments
N/A					

RTO established Planning Reserve Margin requirement ¹ <i>(see IC 8-1-8.5-13 (f))</i>	1,111	970	910	998
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Please describe any other federal reliability requirement:	
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Reliability Adequacy Metrics <i>[defined in IC 8-1-8.5-13(h)]</i>			
Summer RA Metric	Winter RA Metric	Spring RA Metric	Fall RA Metric
109%	129%	132%	131%

1. CEI South PRMR as of April 21, 2026, as provided by MISO in OMS Survey

IC 8-1-8.5-13(l) Reporting Form - Planning Resource Year 1 (2028-2029)
Indiana Utility Regulatory Commission

Add rows below as necessary. For resources located outside of Zone 6, please provide a description of the deliverability arrangements.
For demand response resources, please provide a description of each program.

Owned Resource <i>IC 8-1-8.5-13(l)(1) definition</i>	ICAP (MW) <i>Nameplate capacity</i>	Summer Accredited Capacity (MW) <i>IC 8-1-8.5-13(k) definition</i>	Fall Accredited Capacity (MW) <i>IC 8-1-8.5-13(d) definition</i>	Winter Accredited Capacity (MW) <i>IC 8-1-8.5-13(l) definition</i>	Spring Accredited Capacity (MW) <i>IC 8-1-8.5-13(j) definition</i>	Location: <i>RTO interconnection zone</i>	Fuel Source	Additional Comments
AB Brown 3	80	62.6	65.8	82.9	64.6	MISO Zone 6	Gas/Fuel Oil	Primary fuel is natural gas but can operate on fuel oil
AB Brown 4	80	68.7	63.4	71.9	60.6	MISO Zone 6	Gas	-
AB Brown 5	232.3	204.4	197.5	148.7	191.7	MISO Zone 6	Natural Gas	-
AB Brown 6	232.3	204.4	197.5	148.7	191.7	MISO Zone 6	Natural Gas	-
FB Culley 3	270	186.8	245.4	200.6	229.8	MISO Zone 6	Coal	
OVEC (Ohio Valley Electric Corp.)	32.2	29.4	30.1	30.9	30.1	MISO External Zone 23	Coal	CEI South owns 1.5% share of OVEC's total capacity. OVEC is located in MISO external zone 23, and is interconnected through the transmission provider LGEE (Louisville Gas & Electric) to SIGE with Transmission Service Request reference #4931291.
Future Storage	90	54.9	79.2	76.5	84.2	MISO Zone 6	BESS	Identified in 2025 IRP Preferred Portfolio
Troy Solar	50	22.5	14.0	9.5	20.1	MISO Zone 6	Solar	
Posey Solar	191	85.9	53.5	36.3	77.0	MISO Zone 6	Solar	
Oak Hill Solar	2	0	0	0	0	MISO Zone 6	Solar	Located on CEI South distribution system and accounted for in peak load forecast. Not a SAC resource.
Volkman Rd Solar	2	0	0	0	0	MISO Zone 6	Solar	Located on CEI South distribution system and accounted for in peak load forecast. Not a SAC resource.
Volkman Road Battery	1	0	0	0	0	MISO Zone 6	BESS	Located on CEI South distribution system and accounted for in peak load forecast. Not a SAC resource.
Blackfoot Landfill	3.2	0	0	0	0	MISO Zone 6	LFG	Located on CEI South distribution system and accounted for in peak load forecast. Not a SAC resource.

Contracted Resource <i>IC 8-1-8.5-13(l)(2) definition</i>	ICAP (MW) <i>Nameplate capacity</i>	Summer Accredited Capacity (MW) <i>IC 8-1-8.5-13(k) definition</i>	Fall Accredited Capacity (MW) <i>IC 8-1-8.5-13(d) definition</i>	Winter Accredited Capacity (MW) <i>IC 8-1-8.5-13(l) definition</i>	Spring Accredited Capacity (MW) <i>IC 8-1-8.5-13(j) definition</i>	Location: <i>RTO interconnection zone</i>	Fuel Source	Additional Comments
Benton County Wind Farm	30	0.0	0.0	0.0	0.0	MISO Zone 6	Wind	
Fowler Wind Farm	50	4.0	7.5	11.5	11.6	MISO Zone 6	Wind	
Wheatland Solar	150	67.5	42.0	28.5	60.5	MISO Zone 6	Solar	
Galesburg Wind	147	11.8	22.1	33.8	34.0	MISO Zone 4	Wind	
Salt Creek Wind	170	13.6	25.5	39.1	39.3	MISO Zone 3	Wind	
Aggregator	N/A	25.4	26.3	26.4	25.3	MISO Zone 6	N/A	
Capacity Contracts	N/A	0	0	0	0	N/A	N/A	
Total Contracted Resources		122	123	139	171			

Demand Response Resource <i>IC 8-1-8.5-13(l)(3) definition</i>	Summer Accredited Capacity (MW) <i>IC 8-1-8.5-13(k) definition</i>	Fall Accredited Capacity (MW) <i>IC 8-1-8.5-13(d) definition</i>	Winter Accredited Capacity (MW) <i>IC 8-1-8.5-13(l) definition</i>	Spring Accredited Capacity (MW) <i>IC 8-1-8.5-13(j) definition</i>	Additional Comments
DR-DLC-Thermostats	12	6	0	0	

Resource Retirements <i>IC 8-1-8.5-13(i) definition</i>	Summer Accredited Capacity (MW) <i>IC 8-1-8.5-13(k) definition</i>	Fall Accredited Capacity (MW) <i>IC 8-1-8.5-13(d) definition</i>	Winter Accredited Capacity (MW) <i>IC 8-1-8.5-13(l) definition</i>	Spring Accredited Capacity (MW) <i>IC 8-1-8.5-13(j) definition</i>	Additional Comments
N/A					

Refueled Resources <i>IC 8-1-8.5-13(g) definition</i>	Summer Accredited Capacity (MW) <i>IC 8-1-8.5-13(k) definition</i>	Fall Accredited Capacity (MW) <i>IC 8-1-8.5-13(d) definition</i>	Winter Accredited Capacity (MW) <i>IC 8-1-8.5-13(l) definition</i>	Spring Accredited Capacity (MW) <i>IC 8-1-8.5-13(j) definition</i>	Additional Comments
N/A					

RTO established Planning Reserve Margin requirement ¹ <i>(see IC 8-1-8.5-13 (f))</i>	1,117	971	905	1,007
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Please describe any other federal reliability requirement:	
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Reliability Adequacy Metrics <i>[defined in IC 8-1-8.5-13(h)]</i>			
Summer RA Metric	Winter RA Metric	Spring RA Metric	Fall RA Metric
94%	111%	104%	111%

1. CEI South PRMR as of April 21, 2026, as provided by MISO in OMS Survey

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Midcontinent	)	Order No. 202-26-29
Independent System Operator and	)	
Northern Indiana Public Service	)	
Company LLC	)	

Federal Power Act Section 202(c)	)	
Emergency Order: Midcontinent	)	Order No. 202-26-30
Independent System Operator and	)	
CenterPoint Energy Indiana South	)	

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 198
McFarlane Testimony

Tab C

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

**PREPARED DIRECT TESTIMONY OF
SHAWN MCFARLANE**

1 **I. PROFESSIONAL BACKGROUND AND QUALIFICATIONS**

2 **Q. Please state your name, business address, and position with your employer.**

3 A. My name is Shawn F. McFarlane. I am employed by the Midcontinent
4 Independent System Operator, Inc. (“MISO”), which is located at 720 City Center
5 Drive, Carmel, Indiana, 46032. My current position is Executive Director of
6 Market Operations, which I have held since October 2015. During that time, I
7 have had executive oversight of various functions under MISO’s Open Access
8 Transmission, Energy and Operating Reserve Markets Tariff (“Tariff”), including
9 Resource Adequacy, Day-Ahead Energy and Operating Reserve Market, Auction
10 Revenue Rights and Financial Transmission Rights markets, as well as the
11 Forward Reliability Assessment Commitment, and Market and Transmission
12 Settlements. I joined MISO in April of 2014 and served as Executive Director of
13 Strategy through September 2015.

14 **Q. Please briefly describe your educational and professional background before**
15 **you joined MISO.**

16 A. I hold a Bachelor of Science Degree in Petroleum Engineering at Pennsylvania
17 State University and an MBA in Finance from Rutgers University. Prior to joining
18 MISO, I was employed at Reliant Energy and successor companies from 1998-2013
19 as a Director and then as Vice President in various roles in Business Development,
20 Commercial Analytics, and Wholesale Strategy in the merchant generation, energy
21 trading, and retail energy marketing businesses. Prior to joining Reliant Energy, I
22 was an Engagement Manager at a management consulting firm, McKinsey &
23 Company, in their energy consultancy group from 1996-1998; in various finance

1 roles at Texaco, Inc. from 1990-1996; and, as a petroleum engineer in Southern
2 California Gas Company's natural gas storage unit from 1985-1988.

3 **Q. Please describe your job responsibilities as they relate to this filing.**

4 A. As MISO's Executive Director of Market Operations, I have executive oversight
5 of Resource Adequacy, including administration of MISO's Planning Resource
6 Auction, within which accreditation of resources is a key parameter to better
7 ensure that the Planning Reserve Margin Requirement and Planning Resource
8 volumes are appropriately accurate to better ensure that resources are available to
9 satisfy needs in real time. Additionally, accurate accreditation enables that
10 cleared resources in the Planning Resource Auction are priced appropriately,
11 based on their expected availability.

12 **II. PURPOSE OF TESTIMONY AND RAN PROGRAM OVERVIEW**

13 **Q. What is the purpose of your testimony?**

14 A. My testimony supports MISO's filing in this docket and provides operational and
15 implementation detail associated with MISO's proposal.

16 **III. SEASONAL RESOURCE ADEQUACY CONSTRUCT**

17 **Q. How does MISO propose to meet the challenges of the Reliability Imperative
18 in this filing?**

19 A. As discussed in Mr. Wright's Testimony, the Reliability Imperative is the term
20 MISO uses to describe the shared responsibility of MISO, Load Serving Entities,
21 and Relevant Electric Retail Regulatory Authorities to address the challenges that
22 rapid fleet change, increased frequency and severity of extreme weather events,
23 and other factors are posing to the reliability of the MISO Region. As part of

1 MISO's Market Redefinition efforts in response to the Reliability Imperative,
2 MISO proposes Resource Adequacy enhancements in two primary areas: (1)
3 establishing seasonal Resource Adequacy Requirements (“RAR”); and (2)
4 improving availability-based accreditation. These enhancements are designed to
5 verify sufficient generation adequacy within each Season of the year and to
6 provide the right incentives for resources to maintain system reliability. MISO
7 will be submitting a separate, but related, Minimum Capacity Obligation proposal
8 in another filing concurrent with this filing.

9 **Q. Please describe MISO’s current Resource Adequacy (RA) Construct.**

10 A. In accordance with MISO’s Resource Adequacy Tariff provisions contained in
11 Module E-1, Market Participants representing Load Serving Entities (“LSEs”) are
12 expected to procure sufficient resources to meet their forecast coincident peak
13 load, plus a reserve margin, for the upcoming Planning Year. A detailed
14 description of the provisions of MISO’s existing RAR, including the specific
15 requirements established in Module E-1 of the Tariff, is included in the
16 Testimony of Mr. Scott Wright.

17 **Q. Why is MISO proposing to move to a seasonal RA construct with**
18 **accreditation based on availability during times of need?**

19 A. MISO is proposing to move to a seasonal RA construct so that it can better
20 manage reliability risks brought about by the key trends impacting resource
21 availability identified in 2018 as part of MISO’s Resource Availability and Need

1 (“RAN”) initiative.¹ As described in the Testimony of Mr. Scott Wright, MISO
2 now faces a Reliability Imperative. As part of its response with respect to
3 Resource Adequacy, MISO is focused on addressing the following: (1) Improving
4 outage scheduling and expectations; (2) Linking resource accreditation and
5 requirements with initial focus on Load Modifying Resources (“LMRs”); (3)
6 Aligning Planning Resource Auction (“PRA”) commitments with energy needs
7 all year; and (4) Ensuring flexible resource availability to address changing fleet
8 characteristics. The proposed Tariff enhancements presented in this filing are
9 necessary to further address the Reliability Imperative. Moreover, the urgency of
10 implementing the proposed Tariff enhancements is evidenced by the increased
11 incidence of capacity emergency maximum generation alerts, warnings, and
12 events (collectively referred to as “MaxGens”),² particularly in the Seasons
13 outside of Summer as demonstrated in the chart below. The reasons for and
14 impacts of these changes are described in more detail in the Testimonies of Mr.

¹ See

<https://cdn.misoenergy.org/20180405%20RSC%20Item%2007%20RAN%20Issues%20Statement%20White%20Paper164746.pdf>

² See <https://cdn.misoenergy.org/SO-P-EOP-00-002%20Rev%2012%20MISO%20Market%20Capacity%20Emergency554411.pdf>

1 Scott Wright and Mr. Jameson Smith supporting this filing.



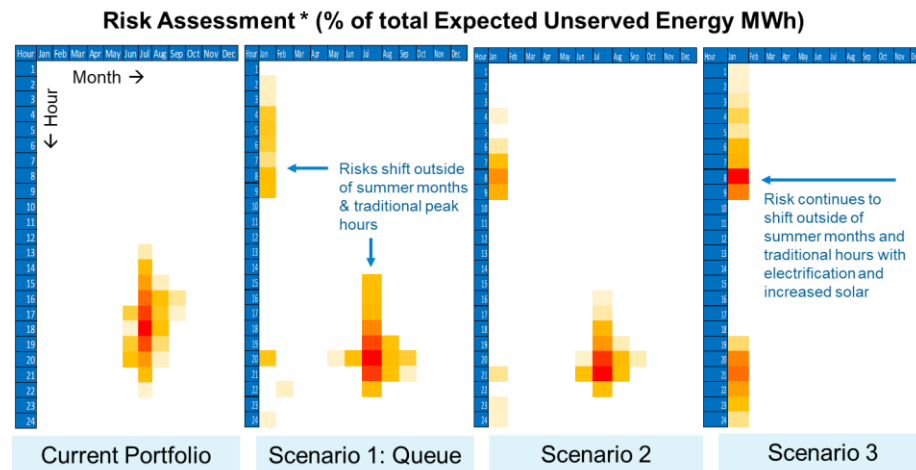
2 Chart indicates the number of days under a max gen alert, warning or event.

3 **Q. How will reliability risks change as MISO's resource portfolio continues to**
4 **evolve?**

5 A. In addition to the increasing number of non-Summer MaxGens that MISO has
6 experienced in the past several years, Loss of Load risks are projected to continue
7 shifting outside of Summer and traditional peak hours. This is expected to be the
8 case under a broad range of plausible future resource portfolio scenarios that
9 MISO has developed and analyzed, as illustrated in the Figure below. Scenario 1
10 represents a 2025 resource mix outlook based on current MISO Generator
11 Interconnection Queue and OMS-MISO survey projected retirements. Scenario 2
12 models a continuation of current trends and largely represents MISO member
13 resource plans and provides a 2030 resource mix as defined in MISO Future 1.³
14 Scenario 3 represents a 2035 resource mix outlook with accelerated existing fleet

³ See <https://cdn.misoenergy.org/MISO%20Futures%20Report538224.pdf>

retirements and adoption of renewables and electrification as defined in MISO
Future 3.⁴



Q. How will a seasonal RA construct address the concerns identified by MISO?

A. Moving to a seasonal RA construct will align seasonal resource accreditation with seasonal resource availability to meet the changing risk profile that is emerging and is expected to increase dramatically in the near future. The proposed change to a seasonal Resource Adequacy construct is expected to mitigate risks to reliability within the MISO footprint by promoting Availability, Visibility, and Flexibility, which are “Key Needs” MISO outlined in the 2019 and 2020 MISO Forward Reports.⁵ For Availability, a seasonal RA construct enables a more accurate representation of resource capability at different times during the year, improves certainty of resource availability outside the Summer Season, and better incentivizes resources to be available when needed. For Visibility, a seasonal RA

⁴ *Id.*

⁵ https://www.misoenergy.org/about/miso-strategy-and-value-proposition/MISO_Strategy/strategy-papers/#nt=%2Fstrategypapertype%3AMISO%20FORWARD&t=10&p=0&s=strategypaperpublisheddate&sd=desc

1 construct establishes seasonal reserve requirements, both system-wide and in
2 LRZs, that better align with risks and deliver additional visibility into the risks
3 throughout the year, which are not currently captured in the annual RA construct.
4 There are also indirect improvements to the flexibility of resources that operators
5 may not have had previously. These resources may improve their characteristics
6 to be able to take shorter outages or need less time to respond. Additionally,
7 consideration of unit lead time for offline units for the purposes of accreditation is
8 a part of the proposal. At implementation, the flexibility required for accreditation
9 purposes is a lead time that does not exceed 24 hours allowing the resource to be
10 committed the day ahead in MISO's existing commitment processes. Finally,
11 these reforms considered together provide the ability for resource owners to
12 commit resources only when they are needed and expands opportunities for
13 resources to participate in the PRA, suspend, or retire.

14 **Q. What changes are necessary to implement the proposed RA construct?**

15 A. Changes include developing seasonal values for a number of construct
16 parameters: MISO's Loss of Load Expectation ("LOLE"); Planning Reserve
17 Margin Requirements ("PRMR"); Local Reliability Requirements ("LRR"); Local
18 Clearing Requirements ("LCR"); Capacity Import Limits ("CIL"); and Capacity
19 Export Limits ("CEL"). In addition, the changes will require accrediting
20 resources by Season based on their availability during times of need.

1 **Q. How does MISO define the various Seasons for its proposed seasonal RA**
2 **construct?**

3 A. The seasonal RA construct will follow the definition of Season as defined in
4 Module A of MISO’s Open Access Transmission, Energy and Operating Reserve
5 Markets Tariff (“Tariff”): Winter (December, January, February); Spring (March,
6 April, May); Summer (June, July, August); and Fall (September, October,
7 November). This definition of Season is used in various MISO processes,
8 including Financial Transmission Rights and seasonal resource assessments.

9 **Q. Why does MISO need to update its LOLE modeling and methodology to**
10 **implement a Seasonal RA construct?**

11 A. The modeling and methodology of the LOLE study needs to change to model
12 seasonally sensitive variables and calculate the construct parameters outlined
13 above more accurately. This can be achieved through: (1) improving sub-annual
14 LOLE modeling, including the modeling of planned outages, modeling of non-
15 firm external support, and hourly modeling of intermittent resources; and (2)
16 seasonal LOLE risk targets and requirement calculations.

17 **Q. What does seasonal forced and planned outage modeling entail?**

18 A. Seasonal forced outage rates based on historic North American Electric
19 Reliability Corporation’s (“NERC”) Generator Availability Data System
20 (“GADS”) data will be used in the LOLE analysis for all thermal units.
21 Additionally, an adjustment will be applied within the model to account for
22 increased forced outages during extreme cold weather events. When the
23 temperature drops below a certain threshold in the model, the outage rates for

1 thermal resources will be increased to reflect the correlation between extreme
2 weather and temperatures and forced outages that are observed in real-time,
3 especially during the Winter Season. This correlation was developed based on
4 five years of historical outage and weather data. Five-year average planned
5 outage rates from GADS by Season, including the observed increases during
6 extreme cold in the Winter Season, will be included in the seasonal modeling for
7 all thermal resources. SERVVM (the software used to conduct the LOLE study)
8 will schedule planned outages using a flexible outage method. This outage
9 modeling method requires a portion of the planned outages to be fixed and then
10 optimally schedules the remaining outages to reflect the actual operational
11 flexibility to do so and maintain reliability.

12 **Q. What does the improvement of non-firm external support in the LOLE**
13 **model entail?**

14 A. Non-firm external support (*i.e.*, imports) will be modeled as a probabilistic
15 distribution input in SERVVM, an enhancement from current modeling practice
16 that uses an annual fixed value. One of the benefits of being part of the Eastern
17 Interconnection is the ability to import energy from neighboring regions as
18 needed, subject to availability. Hourly historical non-firm imports during
19 emergency pricing hours, for the period 2016 to 2019, calculated by subtracting
20 firm import MWs from total import MWs, will be used to determine the
21 probabilistic distribution of non-firm imports into the MISO Region as an input to
22 the LOLE model. During the LOLE simulations, SERVVM randomly draws from
23 this distribution of non-firm imports, which is used to serve the hourly load. This

1 methodology is a better representation of non-firm imports when compared to the
2 current annual approach (which assumes a static value) as it captures the
3 variability observed in operations.

4 **Q. Please describe the enhancements to the treatment of intermittent resources**
5 **in the LOLE model.**

6 A. Instead of modeling wind and solar resources as monthly fixed capacity values
7 under current practice, wind and solar resources will be modeled as hourly
8 profiles that correspond to each of the 30 load shapes within SERVIM to better
9 reflect the availability and variability of these resources across the year. Hourly
10 wind profiles are developed for 30 historical weather years by normalizing
11 historical hourly wind outputs for recent weather years from 2011 to 2019 and
12 constructing synthetic hourly wind shapes for weather years from 1990 to 2010
13 based on temperature correlation.⁶ Figures 4 to 13 in the MISO published sub-
14 annual LOLE Modeling Methodology Document illustrate the close correlation
15 between historical wind output and temperature/load.⁷ MISO believes it is
16 appropriate to use the correlation between wind and temperature to develop wind
17 profiles to reasonably model the relationship of load to wind outputs and have a
18 similar distribution of wind outputs as a function of the 1990-2010 load shapes as
19 seen in the 2011-2019 shapes where actual historical wind outputs are available.
20 Hourly solar profiles for 42 selected sites across the MISO Region are developed
21 using the NREL National Solar Radiation Database Data Viewer from 1998 to

⁶ See https://cdn.misoenergy.org/20201104_RASC_Item_04a_Astrape_MISO_Sub-annual_LOLE_Modelling_Methodology_Document489436.pdf

⁷ *Id.* at 5 – 10.

2019 and processed through the System Advisor Model to generate fixed and tracking solar profiles. The hourly solar profiles for 1990 to 1997 weather years are then selected by using daily solar profiles from the day that most closely matched the peak temp out of all days (+/- 2 days) of the source day from 1998 to 2019.⁸ Similar to wind profiles, using the correlation between solar outputs and temperature reasonably models the relationship between load and solar outputs and creates a similar distribution of solar output as a function of load for 1990 to 1997 as is seen in the 1998 to 2019 time frame.

Q. How will seasonal LOLE targets be determined and Resource Adequacy Requirements be calculated?

A. To determine seasonal Resource Adequacy reserve requirements, the LOLE model needs to have a defined LOLE target for each Season. MISO proposes to round LOLE targets up to a minimum of 0.01 day per year for any Season(s) with LOLE less than 0.01 day per year and maintain LOLE targets for the Seasons with LOLE greater than 0.01 day per year. MISO believes this approach is reasonable considering the practicality of solving the model to a reasonably small LOLE target to determine reserve requirements, as described further below. The following process will be utilized to determine the seasonal requirements via the LOLE analysis. First, an LOLE analysis for the Planning Year will be conducted to solve the model to an annual LOLE of 0.1day per year to determine the natural LOLE distribution, by either adding proxy combustion turbine units with typical size (160 MW) and class average Forced Outage Rate Demand

⁸ See https://cdn.misoenergy.org/20201104_RASC_Item_04a_Astrape_MISO_Sub-annual_LOLE_Modelling_Methodology_Document489436.pdf

1 (“EFORd”) if the LOLE for the Planning Year is greater than 0.1 day per year or
2 a perfect negative unit with zero forced outage rate if the LOLE for the Planning
3 Year is less than 0.1 day per year, consistent with the approach under the current
4 annual construct.⁹ If the LOLE for a Season is equal or greater than 0.01 day per
5 year, the reserve requirement for that Season will be calculated based on this
6 LOLE analysis. If the LOLE for any Season is less than 0.01 day per year, an
7 additional LOLE analysis will be performed to determine the reserve requirement
8 for that Season by adding a perfect negative unit with zero forced outage rate to
9 that Season until the LOLE in that Season reaches 0.01 day per year. In
10 collaboration with stakeholders, the 0.01 day per year LOLE minimum target is
11 chosen for each Season because it is a large enough target to allow the LOLE
12 model to accurately solve to determine seasonal reserve requirements while
13 keeping an annual LOLE largely close to 0.1 day per year. This method also
14 ensures that requirements in Seasons where the LOLE is naturally greater than
15 0.01 day per year are not artificially inflated, which would result in increased cost
16 to Market Participants.

17 **Q. Please describe the seasonal Planning Reserve Margin and Planning Reserve**
18 **Margin Requirements.**

19 A. A Planning Reserve Margin (“PRM”) (expressed as a percentage) will be
20 determined for each of the four Seasons by performing an LOLE analysis with
21 seasonal input assumptions. The LOLE model will be used to meet the seasonal
22 LOLE targets by adjusting the capacity within the model up or down as needed,

⁹ <https://cdn.misoenergy.org/PY%202021%2022%20LOLE%20Study%20Report489442.pdf>

1 as described above. The seasonal PRM values in terms of Unforced Capacity
2 (“UCAP”) will be calculated and expressed as a percentage of seasonal coincident
3 peak demand. The PRM for each Season is multiplied by the 50/50 forecast of
4 coincident peak load to determine the PRMR (in MWs) for that Season.

5 **Q. Please describe the seasonal zonal Local Reliability Requirements and Local**
6 **Clearing Requirements.**

7 A. The zonal Local Reliability Requirements (“LRR”) will be determined using the
8 same two-step process as the PRM analysis. Each Zone will be treated as an
9 isolated system, consistent with the existing LRR analysis methodology under the
10 current annual PRA construct.¹⁰ The seasonal LRR values will be calculated in
11 terms of UCAP and expressed as a percentage of seasonal zonal Coincident Peak
12 Demand once the model has been solved to the appropriate LOLE targets. The
13 seasonal LRR values will be used to determine the seasonal LCR values by
14 subtracting the seasonal Capacity Import Limits (“CIL”) from the seasonal LRR.

15 **Q. Please describe seasonal Capacity Import/Export Limits.**

16 A. Consistent with the existing transfer limit analysis methodology defined in
17 MISO’s Resource Adequacy Business Practices Manual (“BPM”), BPM-011,
18 seasonal transfer analyses will be performed to determine seasonal CILs and
19 Capacity Export Limits (“CELs”), capturing the seasonal variation of transfer
20 limits for each LRZ. Planning Year seasonal peak powerflow models and input
21 files developed from MISO Transmission Expansion Plan (“MTEP”) studies built
22 for timeframes matching the effective periods of transfer limit analysis will be

¹⁰ See <https://cdn.misoenergy.org/PY%202021%2022%20LOLE%20Study%20Report489442.pdf>

1 used to perform transfer analyses for each Season, including Summer Peak, Fall
2 Peak, Winter Peak, and Spring Peak study models. Seasonal MTEP powerflow
3 models will include both approved and planned transmission projects through the
4 MTEP planning process with effective dates on or before the effective date of the
5 study models. Single-element contingencies in MISO and its seams areas will be
6 evaluated and all facilities under MISO functional control and all seams facilities
7 of 100kV and higher will be monitored. First Contingency Incremental Transfer
8 Capacity (“FCITC”) analysis will be performed for each of the seasonal
9 powerflow models to identify limiting constraints with a generation-to-generation
10 transfer model. Additional Generation Limited Transfer and voltage limited
11 transfer analyses may be performed on an as needed basis if certain scenarios
12 occur as described in the BPM for Resource Adequacy. The resulting seasonal
13 Zonal Import Ability (“ZIA”), in conjunction with controllable exports, will be
14 used to subtract from the LRR to determine the seasonal LCR for each LRZ.

15 **IV. RESOURCE ACCREDITATION OVERVIEW**

16 **Q. What is MISO’s current approach to Resource Accreditation?**

17 A. The current resource accreditation process, which for thermal resources is based
18 on Unforced Capacity (“UCAP”), is determined using resource performance
19 between September 1 and August 31 of the three years prior to the Planning Year.
20 Market Participants submit GADS data to MISO on a quarterly basis. This data is
21 utilized to determine Equivalent Forced Outage Rate Demand (“XEFOR”),
22 excluding events outside of management control, which is then used as a
23 component in the calculation of Unforced Capacity. The UCAP is calculated by

1 taking Installed Capacity (“ICAP”), which is the lesser of Generator Verification
2 Test Capacity (“GVTC”) and Total Interconnection Service, multiplied by one
3 minus the XEFORd. UCAP values are communicated to Market Participants on
4 December 15 prior to the Planning Resource Auction. The proposed rules will
5 continue to utilize the same period to evaluate availability for determining
6 Seasonal Accredited Capacity (“SAC”).

7 **Q. How does MISO propose to calculate Resource Accreditation going forward?**

8 A. Resource accreditation should primarily reflect the anticipated capability and
9 availability of Planning Resources during times when they are most needed.
10 Utilizing offered availability and actual performance provides an improved
11 measure of expected availability for each Season.

12 **Q. Which resources will the Resource accreditation proposal affect?**

13 A. All resource types will be generally affected by moving to a seasonal Resource
14 Adequacy construct. However, accreditation for certain resources will be
15 determined based on their availability during times of need, as described in detail
16 below. Specifically, Demand Response Resources and Capacity Resources that
17 are Generation Resources (collectively “Schedule 53 Resources”), but not
18 Dispatchable Intermittent Resources, Intermittent Generation, Electric Storage
19 Resources, External Resources or Use Limited Resources, will be subject to these
20 new availability-based accreditation requirements. The resources designated as
21 Schedule 53 Resources will be subject to the proposed availability-based
22 accreditation methodology established in new Schedule 53 of the Tariff.
23 Resources that are not subject to Schedule 53 will continue to have their

1 accreditation determined generally as it is done today, with appropriate
2 adjustments made to convert their accreditation to a seasonal basis. I note that
3 MISO plans to further evaluate the accreditation methodologies of non-Schedule
4 53 Resources commencing with stakeholder discussions in 2022.

5 **Q. What changes does MISO propose with respect to Resource Accreditation**
6 **for Schedule 53 Resources?**

7 A. The proposed changes align Resource accreditation for Schedule 53 Resources
8 with historic availability and performance during the highest risk periods while
9 also accounting for general availability of resources across the year. More
10 specifically, MISO proposes a two-tiered calculation to determine individual
11 resource accreditation by Season. The first tier will determine each resource's
12 real time offered availability during non-tight operating condition hours, and the
13 second tier will determine each resource's real-time offered availability during
14 hours with the tightest operating conditions, including declared MaxGens. The
15 second tier will be more heavily weighted so that the majority of a resource's
16 accreditation will be based on its availability during times of need. Additional
17 details about the weighting and the proposed transition period to phase in the full
18 80% weighting for Tier 2, are described in detail below.
19 MISO supported its Independent Market Monitor's ("IMM") recommendation to
20 base 100% of accreditation on availability during times of need but introduced a
21 revised two-tier proposal in May 2021 with 20% weighting based on availability
22 during hours that aren't tight to accommodate stakeholder requests that these
23 hours should still be relevant to resource accreditation. The proposal was

1 modified to recognize that general resource availability supports reliability by
2 allowing resources to take needed maintenance outages. Moreover, general
3 resource availability reduces the time the system is operating within the margin of
4 error for capacity sufficiency.

5 Each tier calculation also will account for exemptions obtained by sufficiently
6 coordinating planned outages when determining availability, as described in detail
7 below.

8 **Q. Why are MISO's proposed changes necessary?**

9 A. Historically, most if not all LOLE occurred at or near the annual Coincident Peak
10 Demand for the system, which occurred in the Summer. However, MISO has
11 experienced an increasing number of days with tight operating margins in all four
12 Seasons of the year despite clearing the targeted level of reserves in the PRA each
13 year. This is attributable, in part, to a wave of retirements that began before the
14 start of the 2016/17 Planning Year. Given this and recent operational experiences,
15 including involuntary load shed outside of Summer, MISO has worked with
16 stakeholders to provide tools and incentives to improve the availability,
17 flexibility, and visibility of our resource fleet to mitigate the risks of capacity
18 insufficiency.

19 Resource accreditation should reflect the anticipated capability and availability of
20 Planning Resources during times when they are most needed. Historically,
21 accreditation for conventional generation has been based only on forced outage
22 rates defined in GADS. Recent experience shows this approach does not
23 effectively reflect the actual availability and capability of resources during times

1 when capacity needs are highest – during periods of peak demand, high
2 generation outages, low levels of renewable generation output, or a combination
3 of these which can occur in any Season. Additionally, the current approach to
4 accreditation for conventional thermal resources does not provide the proper
5 incentives to improve availability, especially during critical periods, as described
6 more fully in the Testimony of Mr. Smith.

7 **Q. What benefits does MISO expect to receive from these proposed changes to**
8 **Resource Accreditation?**

9 A. MISO expects the proposed Tariff changes to achieve several important and
10 necessary benefits, including: (1) increased confidence in the accredited capacity
11 MISO can count upon during times of need; (2) improved signals for resource
12 availability during times of need; (3) improved outage coordination processes;
13 and (4) lower non-Summer Season requirements, which will enable seasonal
14 operation of resources, as requested by many resource owners.

15 **Q. How does the proposal mitigate reliability risks during extreme weather**
16 **events?**

17 A. The proposal incentivizes resource availability during times of need and does so
18 specific to each Season. For example, Winter RA Hours have been observed to
19 occur during extreme cold events and decisions and investments which impact
20 resource availability in such conditions (*e.g.*, winterization and firming up of fuel
21 procurement) are expected to have a significant impact on resource availability.

22 **Q. How will MISO's Resource accreditation proposal apply to Schedule 53**
23 **Resources?**

1 A. Resource accreditation for Schedule 53 Resources will no longer be based on
2 forced outage rates from GADS as MISO intends on using energy market offers
3 and related parameters to determine these resources' accreditation. Specifically,
4 their accreditation will be based on Real Time Hourly Emergency Maximum
5 Limits (or Targeted Demand Reduction Level ("TDRL") for Demand Response
6 Resources) information in MISO's Day-Ahead and Real-Time system. If a unit is
7 offline, then its lead time and outage status are also relevant to determine if it
8 could be reasonably committed today to be used tomorrow during a time of need.
9 Other factors such as the type and volume of interconnection service and
10 seasonally corrected GVTC values will be utilized as well to account for changes
11 to deliverability or unit capability not reflected in past offers. The proposed
12 construct will continue to base accreditation on the three prior years starting
13 September 1 through August 31 of the year prior to the Planning Year, which
14 reflects the cumulative availability of a Resource. As noted above, MISO
15 proposes a tiered weighting structure with more emphasis on low operating
16 margin RA Hours to determine individual resource accreditation by Season.
17 Accreditation will be based on each resource's real-time offered availability
18 during all hours with heavier weighting for hours with the tightest operating
19 conditions (*i.e.*, RA Hours) while incentivizing the coordination of planned
20 outages by offering exemptions that remove hours when offers were zero when
21 certain conditions are met.

22 **Q. What are Resource Adequacy hours?**

1 A. Resource Adequacy Hours (“RA Hours”) represent the periods of highest risk and
2 greatest need both during a Season and throughout the Planning Year. They
3 include declared MaxGens and the hours when the operating margin, a measure of
4 available economic supply capacity above demand and reserve requirements, is at
5 its lowest. RA Hours will be determined seasonally, based on declared MaxGens
6 and the tightest operating margin hours subject to a maximum operating margin
7 threshold established at 25 percent. Each Season will have a target of 65 RA
8 Hours (which represents approximately three (3) percent of the hours in a
9 Season). The number of RA Hours in a Season can exceed the target when
10 declared MaxGens during that Season have a duration greater than 65 hours. The
11 number of RA Hours in a Season can be less than the target because of the 25
12 percent maximum operating margin threshold. In this latter case, these Seasons
13 will have an RA Hour deficiency equal to the difference between the target of 65
14 RA Hours and the actual number of RA Hours.

15 **Q. How does MISO ensure resources have a minimum target number of**
16 **Resource Adequacy Hours?**

17 A. MISO proposes to ensure resources have a minimum of 65 RA Hours for any
18 Season for which they were designated for RAR by multiplying the number of
19 deficient hours for a Season with the Annual Average Offered Capacity
20 (“AAOC”) over all RA hours for that resource during the same annual period (*i.e.*,
21 September to August). It is necessary to have a minimum number of RA Hours to
22 support stability of accreditation values and avoid situations where a Resource
23 loses most of its capacity value for the Season because it happened not to be

1 available on the one or two days when operating margins were at their lowest for
2 the Season. The RA Hours used for determining the AAOC for a resource are the
3 tightest 3 percent of operating margin hours and declared MaxGen hours
4 whenever they occur over the same annual period provided a resource was
5 designated for RAR and had not secured an exemption. The target number of
6 hours for AAOC is 260 for the annual period (*i.e.*, 65 hours per Season multiplied
7 by four Seasons) with the distribution based on tightness and MaxGens rather
8 than a specified target in any Season. Historical analysis shows many of these
9 hours have occurred in the Summer during recent Planning Years. MISO believes
10 it is prudent to supplement deficient seasonal RA Hours with a proxy-based on
11 AAOC as it reflects the next best available information about a resource's
12 availability during times of need, which is a core focus of MISO's proposed
13 enhancements to resource accreditation.

14 It is important to note that, despite the general discussion above about how RA
15 Hours are identified for a Season, ultimately the set of RA Hours are specific to
16 each resource being accredited because of outage exemptions, capacity
17 replacement requirements (each as described later in my testimony), and
18 differences in resource commitment over the three-year look back period. No
19 resource can have more RA Hours than the amount that has been identified for a
20 Season or year, but many resources will have fewer RA Hours requiring more of a
21 resource's accreditation to be based on availability during times of need during
22 the annual period and not just the specific Season to ensure sufficient sample sizes
23 for RA Hours to support stability of resource accreditation.

1 **Q. How will the location of a resource impact its RA Hours?**

2 A. To reflect the varying risk of capacity insufficiency across the MISO Region,
3 Resource Adequacy hours are defined within the First Planning Area (*i.e.*, MISO
4 North/Central) and the Second Planning Area (*i.e.*, MISO South) separately. RA
5 Hours will be determined on this sub-regional basis to reflect the growing
6 frequency of MaxGens that occur on either side of the Sub-Regional Power
7 Balance Constraint, as demonstrated in the below chart:

8

9

Region of highest severity	# of MaxGens
Central	3
North/Central	9
South	21
Footprint	7
Total	40

10

11

12

13

14 MaxGen Events are often the result of issues that disproportionately impact one
15 Planning Area or the other but are usually not felt uniformly across the entire
16 MISO region. Typically, these issues include: trapped capacity in one sub-region
17 due to the contractual transfer limits; increasing sub-regional challenges driven by
18 portfolio differences; and, the varying locational impacts of extreme weather,
19 including hurricanes, cold weather events, and renewable penetration.

20 **Q. How is the hourly Operating Margin percentage calculated?**

21 A. As described in Schedule 53, the Operating Margin is determined using historical
22 information to identify Seasonal RA Hours and Annual RA Hours within the three

(3) most recent periods beginning September 1st and ending August 31st. The Operating Margin Equation is as follows:

$$\text{Operating Margin (\%)}_j = \frac{\text{Online margin (MW)}_j + \text{offline margin (12 - hour lead time)(MW)}_j}{\text{Real Time (RT) Load (MW)}_j}$$

Where:

$\text{Online margin (MW)}_j = \sum_{\text{unit } i \text{ in region } j} (\text{EmergencyMax}_i - \text{Energy MW}_i - \text{cleared operating reserve}_i)$ For all Resources online and under normal dispatch control.

$\text{Offline margin (MW)}_j = \sum_{\text{unit } i \text{ in region } j} \text{Emergency Max}_i - \text{cleared offline supplemental reserve(MW)}_j$ For Resources where all of the following is true: (i) Resource is Offline; (ii) it's cold-start lead-time is less than or equal to 12 hours; and (iii) it's not on outage.

Q. Why does MISO propose to use a 12-hour lead time for offline resources in the Operating Margin calculations?

A. Previously MISO proposed a 24-hour lead time but the IMM suggested that use of a shorter lead time would better reflect the actual operating margins MISO is seeing in real-time operations, which may be impacted by uncertainty that occurs after the deadline to commit longer lead resources has passed. MISO agrees that the use of a shorter threshold better reflects historical margins in the recent past, as evidenced by the chart below. It also leads to the identification of more RA Hours below the 25% operating margin threshold used to identify RA Hours. Moreover, twelve hours leads to more RA Hours being identified in each Season,

allowing resource accreditation to be based on availability during a specific Season with less need to fill in deficient hours through the use of the AAOC, as explained above.

Seasonal Tier 2 tight condition hours are defined across the year based on retrospective tight supply time periods and MaxGen event hours

- RA hours are defined as tight margin hours and emergency hours over four historical planning years
- Margin (%) = online margin + offline margin (24-hour lead time) / Real-Time (RT) load
 - Tight margin hours (RA hours) are selected through the following process for Central+North and South separately:
 - (1) MaxGen hours automatically become RA hours
 - (2) For each season in each Planning Year, supplement number of RA hours to 3% of hours in each season (65 hours)
 - (3) Exclude hours if margin is greater than 25%. Therefore, some seasons will have less than 65 hours cells highlighted below

Sample Calculation		Central + North					South				
Planning Year	Summer	Fall	Winter	Spring	Total		Summer	Fall	Winter	Spring	Total
2018-2019	65	65	54	4	188		65	65	15	65	200
2019-2020	65	49	0	0	114		65	65	7	2	139
2020-2021	65	19	65	37	186		65	65	100	28	258
Total	195	133	119	41			195	195	112	95	

Q. Why is MISO using a 12-hour lead time to identify RA Hours but a 24-hour lead time for accreditation in Schedule 53?

A. As described above, due to the operational uncertainties that MISO faces, tight conditions are more likely to be identified 12 hours before a projected capacity shortfall than 24 hours. Use of a 12-hour threshold better identifies RA Hours that represent “times of need.” On the other hand, the use of a 24-hour threshold for accreditation with respect to offline resources better reflects whether MISO could have reasonably committed a resource in its Day-Ahead Market or Forward Reliability Assessment Commitment processes. This is consistent with the goal of MISO’s RAN initiative to close the gap between planning and operational outcomes. MISO’s proposal bases most of a resource’s accreditation on its offers during times of need but the process of identifying RA Hours that reflect times of

1 need must also account for resources that could not be accessed due to long start-
2 up and notification times.

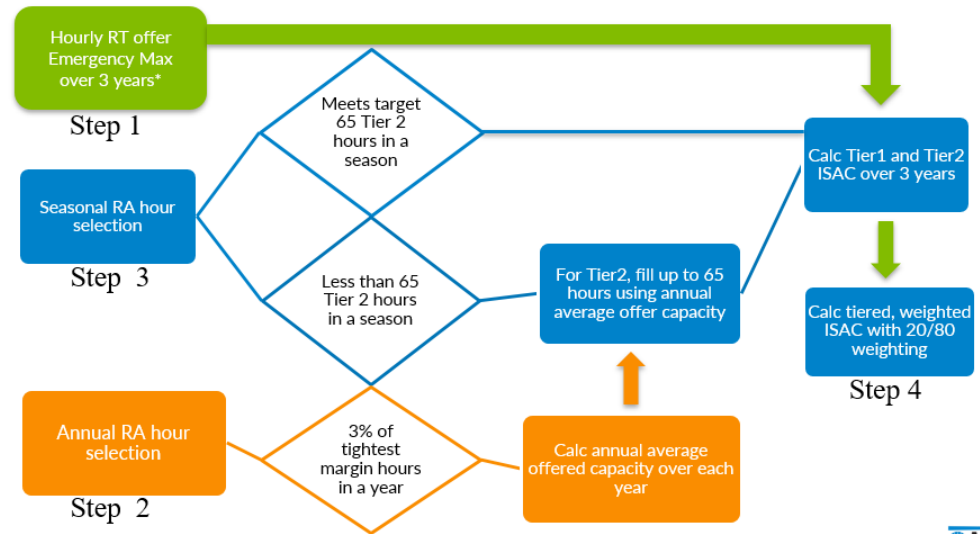
3 **Q. Why is a 25% margin threshold applied in identifying Resource Adequacy**
4 **hours?**

5 A. MISO has examined the distribution of Operating Margin and Operating Margin
6 levels for historical MaxGen events. The evaluation indicates that a 25% margin
7 threshold captures the vast majority of declared MaxGens events. Also, by
8 examining the cumulative count of hours at different levels of Operating Margin
9 in each Season, MISO found that the 25% threshold provides a reasonable
10 balance between having an adequate number of RA Hours for each Season and
11 selecting the set of RA Hours that are truly tight.

12 **Q. Please provide a step-by-step description of the Intermediate SAC**
13 **calculations in Schedule 53.**

14 A. First, a Resource will have its Intermediate Seasonal Accredited Capacity
15 (“ISAC”) determined based on offers of its Real-Time Hourly Emergency
16 Maximum Limit, or TDRL for Demand Response Resources, during both
17 seasonal RA Hours (Tier 2) and Non-RA Hours (Tier 1), as set forth in Schedule
18 53. References to “RT offers” in the steps below refer to Hourly Emergency
19 Maximum Limit or TDRL as applicable. The following graphic illustrates the
20 process of calculating Tier 1 and Tier 2 ISAC for a Resource.

Process of Calculating Tier 1 and Tier 2 Seasonal Accredited Capacity (SAC)



9

*Accreditation calculations are based on data between September 1 and August 31 for the previous 3 years



Step 1: Cap Real-Time offers for the three-year look back period by the relevant seasonally corrected GVTC value to account for a resource’s most recently demonstrated capability. For resource’s that have increased their capacity, MISO will increase the RT offers based on a class average SAC percentage for hours prior to such increased capacity to reflect the additional capacity. Ensure RT offers equal zero when a Resource is on outage or is offline and has a combined Start-Up Time and Start-Up Notification Time greater than 24 hours to reflect that the resource was not available in the Day-Ahead commitment processes.

Step 2: For each year in the three-year look back period (September 1 – August 31) identify declared MaxGen hours and then the tightest non-MaxGen hours needed to reach 260 hours (3%) for the relevant Planning Area in which the resource is located and then remove any hours during which the Resource had a Tier 2 Planned Outage Exemption. The remaining hours are the Annual RA Hours for the resource. Sum the RT offers and divide by the number of Annual

1 RA Hours for the Resource to calculate its Average Annual Offer Capacity
2 (“AAOC”) for each year in the three-year look back period.

3 Step 3: For each Season, identify declared MaxGen hours and then the tightest
4 non-MaxGen hours with operating margin less than 25% for the Planning Area
5 that needed to reach the target of 65 hours (3%). Then remove any hours during
6 which the Resource had a Tier 2 Planned Outage Exemption. If the Resource has
7 less than 65 hours in any Season MISO will add hours with RT offers equal to the
8 relevant AAOC for any deficient hours. MISO will sum up the RT offers during
9 RA Hours for the Season over the 3-year look back period and divide by the total
10 number of hours (195 or greater) to determine the Tier 2 ISAC value for each
11 Season. Calculate the Resource’s Tier 1 ISAC value for each Season by summing
12 the RT offers for any non-RA hours over the 3-year look back period (after first
13 removing any hours for which the Resource had a Tier 1 Planned Outage
14 Exemption) and then dividing by the total number of hours.

15 Step 4: Multiply the Resource’s Tier 1 and Tier 2 ISAC values for each Season by
16 their weightings (20% for Tier 1 and 80% for Tier 2 after the proposed transition)
17 to calculate its final ISAC value.

18 **Q. What does “Intermediate SAC (ISAC)” mean in Schedule 53?**

19 A. Schedule 53 describes various steps in the calculation of SAC and until the very
20 end the “in process” value is referred to as “intermediate” SAC or “ISAC.” Each
21 Resource will have four ISAC values (one for each Season of the upcoming
22 Planning Year) while the SAC calculation is in process.

23 **Q. How does the ISAC value become SAC?**

1 A. Once the final ISAC for each Resource has been determined for each Season of
2 the upcoming Planning Year, then a system-wide conversion ratio is determined
3 for each Season and applied to each Resource's ISAC to determine a Resource's
4 final SAC value for each Season.

5
$$RATIO \frac{UCAP}{ISAC} = \frac{Sum(UCAP_{Schedule\ 53\ Resources})}{Sum(ISAC_{Schedule\ 53\ Resources})}$$

6
7

8 **Q. Why is a conversion ratio necessary and why is it applied as the final step to**
9 **calculate SAC in Schedule 53?**

10 A. MISO's IMM originally suggested, and MISO adopted, a proposal that would
11 scale seasonal requirements by the change in accreditation under Schedule 53 to
12 ensure alignment with how requirements were determined during the LOLE study
13 conducted under a UCAP approach. However, this approach required changes to
14 how PRMR and LCRs are determined and appeared likely to have several
15 unintended consequences, including the relative share of accreditation between
16 Schedule 53 (generally thermal resources) and non-Schedule 53 Resources.
17 Subsequently, the IMM proposed a simpler methodology that avoided the issues
18 noted by having the required scaling occur at the end of the calculations proposed
19 in Schedule 53, thereby removing the unneeded and unintended impacts to
20 auction requirements and non-Schedule 53 resources. Additionally, the revised
21 proposal addressed stakeholder concerns on deliverability and revenue reduction.
22 The IMM presented its new recommendation at the October 6, 2021 meeting of
23 the RASC, and formal feedback was solicited. Feedback received from

1 stakeholders was generally in support of the revised conversion method and
2 MISO adopted the revised method and shared related Tariff redlines at the
3 November 11, 2021, meeting of the RASC.

4 **Q. How will the tiers be weighted?**

5 A. The ISAC value is the weighted average over its values from the two tiers as
6 calculated in the steps above. Ultimately assigning heavier weighting for Tier 2
7 tight condition hours ensures the alignment between a resource's Seasonal
8 Accredited Capacity value and its availability and performance during times of
9 highest risk and greatest need in MISO's Planning Areas. The corresponding tier
10 weightings, which will be effective following a two Planning Year transition
11 (described below), are:

$$12 \quad ISAC_{Tier1_weighting} = 20\%$$

$$13 \quad ISAC_{Tier2_weighting} = 80\%$$

$$14 \quad ISAC = ISAC_{Tier1_value} \times ISAC_{Tier1_weighting} \\ 15 \quad + ISAC_{Tier2_value} \times ISAC_{Tier2_weighting}$$

16 **Q. Is there a transition to the 80% weighting for Tier 2?**

17 A. Yes. Stakeholders requested a transition and MISO felt it would be appropriate to
18 phase in the full 80% weighting until the third Planning Year ("PY") following
19 initial implementation (i.e., the 2025/2026 Planning Year). Doing so will account
20 for the fact that the historical RT offers, outages, and notification times used in
21 the Schedule 53 calculations were submitted for resources without knowledge of
22 the final accreditation methodology proposed in the instant filing. Under the
23 proposal, Tier 2 would start at 60% in PY 2023/24, rise to 70% in PY 2024/25
24 and then reach the full 80% in PY 2025/26.

- 1 **Q. What is the ultimate product of this process?**
- 2 A. The ultimate product of Schedule 53 is four SAC values for each Resource, one to
3 be used for each Season commencing with the upcoming Planning Year 2023/24.
- 4 **Q. How will MISO account for resources with insufficient performance data,**
5 **such as new resources?**
- 6 A. Units with insufficient performance data will utilize a class average proxy for
7 accreditation as done today, but this class average will be based on SAC rather
8 than UCAP. Class averages will be determined for each resource type as they are
9 today. However, the class average will be a ratio of SAC to ICAP for a particular
10 class. A new resource will apply this ratio to its ICAP to determine its SAC. A
11 resource will only use a class average for a Season when there is less than 60 days
12 of real-time offered availability for that Season during a time when the resource
13 was designated for RAR. However, for Planning Year 2023/24 MISO
14 accommodated a stakeholder request by adding Tariff language giving a resource
15 that hadn't been designated for RAR in a recent annual PRA the option to have its
16 accreditation based on its real-time offers rather than a class average.
- 17 **Q. Does MISO's proposal account for seasonal resource deliverability?**
- 18 A. Yes, it does. For seasonal deliverability, similar to the current process, if a
19 Resource does not have full Network Resource Interconnection Service ("NRIS")
20 granted for its seasonal GVTC, to the extent the output is within the total granted
21 Energy Resource Interconnection Service ("ERIS") and does not violate the
22 generator's Generator Interconnection Agreement ("GIA"), it can: (1) request

1 additional NRIS through the established process in Attachment X; or (2) procure
2 firm Transmission Service Requests to align with seasonal deliverability needs.

3 **Q. How will MISO’s proposal address deliverability requirements?**

4 A. The recently accepted ICAP deliverability Tariff changes remain in effect without
5 modification as these requirements are appropriately applied to each Season under
6 the proposal. However, based on stakeholder feedback, MISO will continue to
7 evaluate whether additional modifications to these requirements are needed in the
8 future.

9 **Q. How will MISO’s accreditation proposal apply to wind resources?**

10 A. Wind resources are currently accredited through an annual Effective Load
11 Carrying Capability (“ELCC”) methodology with capacity credits allocated based
12 on each individual wind resource’s performance over eight peak demand hours
13 for the year, historically occurring in the Summer. Similarly, under a seasonal
14 construct, accreditation for each Season will be based on seasonal ELCC studies
15 with capacity credit allocated based on eight peak hours for each Season.

16 **Q. How will MISO’s accreditation proposal apply to non-wind intermittent and**
17 **Energy Efficiency Resources?**

18 A. Seasonal accreditation for non-wind intermittent resources (such as run-of-river
19 hydro, solar, and biomass) and for Energy Efficiency Resources will be based on
20 historic output during hours ending 15, 16 and 17 EST for the relevant Spring,
21 Summer, and Fall months. Winter accreditation will be based on hours 8, 9, 19
22 and 20 EST for the Winter months. The selected hours represent the typical
23 seasonal peak demand hours for the specified Seasons.

1 **Q. How will MISO’s accreditation proposal apply to Demand Resources?**

2 A. MISO’s May 2020 Tariff filing that was accepted by FERC will also be
3 implemented with the 2022-2023 Planning Year. That filing accredits Demand
4 Resources registering as Load Modifying Resources (“LMRs”) based on lead time
5 and number of calls per year.¹¹ The lead time requirements will remain
6 unchanged, but the number of calls will be modified to transition to a seasonal
7 construct. LMRs must be available for a minimum number of calls for each
8 Season as follows: five for Summer, five for Winter, three for Spring, and three
9 for Fall to be eligible to offer into the PRA for each respective Season.
10 Establishing a minimum number of calls per Season rather than per Planning Year
11 is consistent with procuring seasonal capability to meet seasonal needs and incurs
12 a minimum obligation to inform offers into each Season. Demand Response
13 Resources that are not registering as LMRs will be accredited pursuant to
14 Schedule 53 since they submit offers in the day-ahead markets and can be
15 appropriately accredited based on their availability during times of need.

16 **Q. How will MISO’s accreditation proposal apply to behind-the-meter**
17 **generation?**

18 A. Intermittent Behind the Meter Generation (“BTMG”) will be accredited like all
19 other non-wind intermittent resources (such as run-of-river hydro and solar),
20 under a seasonal construct. As described above, accreditation will be based on
21 historic output during hours ending 15, 16 and 17 EST for the relevant Spring,
22 Summer, and Fall months. Winter accreditation will be based on hours 8, 9, 19

¹¹ See *Midcontinent Independent System Operator, Inc.*, 127 FERC ¶ 61,138 (August 14, 2020).

1 and 20 EST for the Winter months. Thermal BTMG with historic GADS data
2 (i.e., with capacity greater than or equal to 10 MW) will be accredited based on
3 their seasonal forced outage rates as it is today. Thermal BTMG with no GADS
4 history will be accredited based on the class average seasonal forced outage rates.
5 FERC approved notification times for LMRs and call limits for DR in MISO's
6 May 2020 filing described in the answer to the prior question. In transitioning to
7 the proposed seasonal capacity construct, all LMRs, including, BTMG, will be
8 subject to those same call limits on a seasonal basis: five for Summer, five for
9 Winter, three for Spring, and three for Fall.

10 **Q. How Will Generation Verification Test Capacity ("GVTC") requirements**
11 **change under MISO's proposal?**

12 A. The current GVTC process has three steps: (1) Generator Operators ("GO")
13 conduct a real power test or base GVTC on operational data between September 1
14 and August 31 prior to the Planning Year; or (2) Correct to historical MISO
15 Summer coincident peak conditions, and (3) Submit in PowerGADS through the
16 MISO Market Portal by October 31 prior to the Planning Year. A GADS
17 integration is run to bring the GVTC from PowerGADS to the Module E Capacity
18 Tracking ("MECT") tool. Under a seasonal construct, the GO would still conduct
19 a real power test or base GVTC on operational data between September 1 and
20 August 31. MISO would publish four historical MISO coincident seasonal peak
21 dates and times for the last five years. The GO will correct the single test to each
22 of the seasonal peak conditions for temperature and submit four seasonally
23 corrected GVTC values by October 31.

1 **Q. Will MISO still permit Installed Capacity deferral?**

2 A. Installed Capacity (“ICAP”) deferral, formerly known as GVTC Deferral,
3 requires a Market Participant to submit notice by February 15, post credit no later
4 than March 1, and test and submit test results before the last business day of May
5 prior to the start of the Planning Year. The February 15 notice and March 1 credit
6 posting timeline still apply, and the credit requirement will continue to be
7 calculated as the deferred ICAP megawatts multiplied by 90 days of the annual
8 Cost of New Entry (“CONE”). However, the deferral notice will be modified to
9 indicate to which Season the deferral applied and the credit would be held until
10 the resource tested. The testing would need to be performed and submitted prior
11 to the last business day prior to the start of the applicable Season, otherwise the
12 existing ICAP Deferral Non-Compliance Charges would apply. No changes are
13 proposed to the ICAP Deferral Non-Compliance Charges.

14 **V. PLANNING RESOURCE AUCTION**

15 **Q. What changes to the PRA will be needed to implement the Seasonal**
16 **construct?**

17 A. The seasonal construct will require a number of important changes relative to the
18 annual construct, including: how MISO conducts the Simultaneous Feasibility
19 Test (“SFT”); time needed to run the PRA; need for non-Summer seasonal
20 forecasts; calculation of non-Summer transmission losses; seasonal must offer
21 requirements, capacity replacement requirements, and non-compliance charges;
22 calculation of the Auction Clearing Price (“ACP”) during shortage or near-

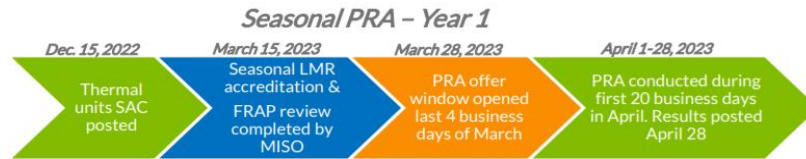
1 shortage conditions; calculation of offer cap impacts; and, establishing a new
2 make whole payment mechanism. Each of these changes is discussed below.

3 **Q. How will MISO conduct the SFT as part of the seasonal PRA?**

4 A. Participants in the PRA may offer resources for each Season in the upcoming
5 Planning Year during the PRA offer window period, which occurs over the last
6 four business days in March. During the first 20 business days in April, MISO
7 will build four SFT models to meet seasonal requirements. Results for each
8 upcoming Season of the Planning Year that pass the SFT auction run will be
9 posted and valid by the 20th business day in April. Results for Seasons where
10 unacceptable constraints are found will have their SFT model rebuilt and re-run
11 for one additional iteration. MISO will accept the result with fewest MWs of
12 network violations of the two iterations for that Season and post the result by the
13 20th business day of April.

14 **Q. How will the proposed seasonal construct affect auction timing?**

15 A. Under a seasonal construct, all four seasonal auctions will occur at approximately
16 the same time as the current annual PRA. The PRA offer window will remain as
17 the last four business days of March. The auction period will be expanded from
18 10 business days to occur within the first 20 business days of April, allowing a
19 maximum of two SFT auction run iterations per Season. PRA Results for each
20 Season will be posted on the 20th business day in April. The following graphic
21 summarizes the timeline leading up to the start of the 2023/2024 Planning Year
22 on June 1:



Q. Will LSEs be required to submit seasonal load forecasts?

A. Yes, the current annual load forecast submittal process will be repeated for each Season. LSEs will supply Coincident Peak Demand and LRZ Peak Demand forecasts for each Season including the estimated demand from forecasted demand resources, whether registered as LMRs or not registered with MISO. The forecasts will also include demand that would have occurred but for the existence of energy efficiency resources that have been in operation less than 4 years. All submissions for such forecast values will include distribution losses but not transmission losses. All demand forecasts will reflect a 50 percent probability that the demand will not exceed the forecasted demand for the relevant time period.

Q. How will the proposal impact the treatment of transmission losses?

A. Under the current annual PRA construct, MISO calculates annual transmission losses for each Local Balancing Authority Area and LRZ based on the MISO coincident peak hour. Under the seasonal PRA construct, transmission losses will be calculated at each of the four published MISO seasonal peak hours and will be made available on both the market portal and its public website.

Q. How will must offer obligations for cleared Capacity Resources be impacted by MISO's seasonal proposal?

A. Currently resources are committed for an entire Planning Year and their must-offer obligation is the same throughout the year despite lower load expectations

1 outside of Summer. Under a seasonal approach, resource capabilities and
2 capacity requirements will be tailored to each Season and resources may be
3 committed for one Season but not committed in other Seasons. The must-offer
4 obligation only applies for those Seasons when a Resource is committed.
5 The must offer obligation will be ICAP multiplied by the percentage of total
6 ZRCs a resource clears (*e.g.*, a unit eligible for 10 ZRCs that clears 5 will have a
7 must offer of 50% of its ICAP).

8 **Q. Will MISO require replacement of ZRCs if a resource has a planned outage**
9 **or derate?**

10 A. Yes, but only if the Generator Planned Outage or derate exceeds 31 days during a
11 Season when the resource is committed. The proposal establishes a maximum
12 threshold number of 31 days of full or partial Generator Planned Outages per
13 Season that will require replacement when exceeded. A threshold of 31 days is
14 reasonable as it retains much of the latitude resources need to schedule Generator
15 Planned Outages while putting an upper limit on the amount of a Season that a
16 committed resource can choose to miss without consequence under MISO's
17 Resource Adequacy construct. Additionally, resources with unplanned outages
18 that were known or could have been reasonably anticipated at the time of the PRA
19 will also have a capacity replacement requirement where the full or partial
20 outages exceeds 31 days since the outage was expected despite not being a
21 Planned Generation Outage. An after-the-fact determination will be made
22 following each Season to determine if resources were on planned outages or
23 planned derates that exceeded the threshold and if such resources met the

1 replacement requirements. Future non-Summer seasonal PRMRs are expected to
2 be lower than today's annual Summer-peak target, representing an efficiency in
3 the amount of required capacity for the MISO Region. Currently, capacity
4 replacement requirements are only in place for capacity suspensions and
5 retirements. Under a seasonal construct with lower PRMRs, the performance and
6 availability of committed capacity to meet seasonal requirements will be critical.
7 Relying on resources that have submitted planned outages for a large portion of a
8 Season is not consistent with availability-based accreditation and seasonal
9 requirements.

10 A non-compliance charge will be assessed for days exceeding the threshold (as
11 described further below) since some resource owners may not be willing or able
12 to replace their capacity with uncleared ZRCs deliverable to the needed LRZ in
13 the relevant Season. It should be noted that exemptions granted through the
14 outage coordination process are not relevant to capacity replacement and will not
15 relieve a resource owner of the ZRC replacement obligation. MISO systems and
16 processes will continue to accommodate ZRC replacement transactions. Current
17 replacement rules regarding deliverability and zonal transfer limits will still apply.

18 **Q. Why is MISO imposing a charge for failure to replace ZRCs associated with**
19 **a retired or suspended resource or a resource that exceeds its maximum**
20 **outage or derate threshold in a season?**

21 A. Currently, resources that convert UCAP to ZRCs and retire or suspend prior to the
22 end of the Planning Year and fail to replace do not face any explicit non-
23 compliance charges under the Tariff. This creates uncertainty and fails to

1 quantify the consequences of failure to replace. In the past, this has led Market
2 Participants to seek waivers from FERC as opposed to complying with the Tariff
3 requirements. The proposal is to implement a financial charge that incentivizes
4 replacement of ZRCs that are retired, suspended, or have outages that exceed 31
5 days in a Season. This non-compliance charge is reasonable because, despite the
6 owner of the resource benefitting from its committed ZRCs each day of the
7 Season, the resource owner has decided to make itself unavailable for more than
8 one month of the three-month Season, thus possibly failing to be available when
9 needed to support reliability in line with our one day in ten-year standard. The
10 proposed Capacity Replacement Non-Compliance Charge will be based on the
11 number of days where a Market Participant had a replacement requirement but
12 failed to do so multiplied by the amount of ZRCs that failed to be replaced
13 multiplied by the sum of the Auction Clearing Price and the daily CONE value.
14 Effectively the resource will stop receiving the Auction Clearing Price for
15 clearing and start paying a daily CONE payment that reflects the missing capacity
16 in the applicable LRZ. Distribution of Capacity Replacement Non-Compliance
17 Charges will be distributed to Market Participants representing LSEs that have
18 met their PRMR during the Planning Year on a pro rata basis, based upon the
19 Market Participant's share of total PRMR for the MISO Region. Billing,
20 invoicing, default, and uplift provisions will be similar to the ICAP Deferral Non-
21 Compliance Charge.

22 **Q. What are the eligibility criteria for ZRCs to be used for capacity**
23 **replacement?**

1 A. As is the case today, only uncleared ZRCs can be used for capacity replacement.
2 ZRCs must be registered and converted in advance as part of the PRA process.

3 **Q. With the proposed move to seasonal auctions how is MISO mitigating the**
4 **risk of capacity revenue insufficiency for resources or payment above annual**
5 **CONE for LSEs?**

6 A. The move to seasonal auctions could lead to concerns about over or
7 underpayment in certain circumstances. Based on historical PRA results, MISO
8 does not expect such circumstances to occur frequently but considers it prudent to
9 ensure reasonable mitigation in the unlikely event of such outcomes. MISO's
10 proposal incorporates enhancements to offer caps and make whole provisions that
11 ensure appropriate resources recover their costs when committed for the PRA
12 while also ensuring that LSEs are not exposed to ACPs that result in charges that
13 amount to multiples of annual CONE value as result of auction participation.
14 Additional details about these enhancements are provided below.

15 **Q. Will the PRA continue to include offer caps?**

16 A. Yes. An LRZ may fail to clear its target PRMR in fewer than all four Seasons.
17 Seasonal offer caps and facility-specific reference levels need to take this into
18 account to enable some resources to economically participate in the seasonal
19 auctions. Offers higher than the daily allocation of the annual CONE value (*i.e.*,
20 "daily CONE" or CONE/365) could be cleared and/or set prices when needed to
21 enable resources to cover their avoidable costs. Therefore, ZRC Offers will be
22 enabled to recover a resource's costs if they only clear in one Season by enabling
23 the Auction Clearing Price to be set at a level up to annual CONE divided by the

1 number of days in each Season, (*e.g.*, CONE/91 days, up to approximately \$1,000
2 per megawatt day). As a result, the Auction Clearing Prices for individual LRZs
3 and Seasons may clear above the current daily value of Annual CONE
4 (CONE/365 or ~\$250/MW-day), which is the highest price at which the current
5 annual Planning Resource Auction can clear when there are insufficient ZRC
6 Offers to meet auction requirements. Consequently, if no further action is taken,
7 the auction could provide revenues up to four (4) times Annual CONE if all
8 Seasons cleared in shortage conditions.

9 **Q. Will the proposal mitigate the potential for recovering above the annual**
10 **CONE?**

11 A. Yes. The proposal includes provisions to mitigate, but not completely eliminate,
12 the potential for annual auction revenue charges to exceed CONE on a per
13 Megawatt-Year basis. An ex-post adjustment will set reduced Auction Clearing
14 Prices when more than one Season clears in ZRC Shortage Conditions or ZRC
15 Near-Shortage Conditions. The final Auction Clearing Price will be set based on
16 annual CONE and the number days in all applicable Seasons when an LRZ, group
17 of LRZs, or the MISO footprint clear with less than the required number of ZRCs
18 or the Season's initial Auction Clearing Price clears above daily CONE in a
19 Planning Resource Auction.

20 **Q. Given the mitigation described above, could annual auction revenue charges**
21 **exceed CONE on a per Megawatt-Year basis?**

22 A. Yes, whenever the Planning Resource Auction clears at least one Season, but
23 fewer than all Seasons with Auction Clearing Prices above the daily value of

1 CONE, it is possible that the Planning Resource Auction charges for all four
2 Seasons could exceed annual CONE on a per Megawatt-Year basis. For example,
3 when one Season clears at CONE due to shortage and the other three Seasons
4 clear less than the daily CONE value. In this situation, MISO will not adjust any
5 of the Auction Clearing Prices and any revenues collected in the non-shortage
6 Seasons would increase the annual auction charge amounts beyond annual CONE
7 which is being fully collected in the one Season which has a shortage. For
8 example, if Summer clears in shortage conditions at CONE divided by 92 days
9 (\$1,001 MW-day) and then Fall at \$20/MW-day, Winter at \$25/MW-day, and
10 Spring at \$15/MW-day the total annual auction revenue charges would equal
11 \$97,575 per MW for the Planning Year, 6% above the CONE value for the Local
12 Resource Zone of \$92,100/MW-year.

13 **Q. Are the mitigation provisions sufficient to minimize annual charges above**
14 **CONE?**

15 A. Yes. While the proposed offer caps and Auction Clearing Price adjustments
16 could result in annual charges exceeding CONE, the likelihood should be
17 infrequent and minimized. Historically, the Planning Resource Auction, has only
18 cleared above the default economic withholding threshold two times: the first
19 was during the 2016-2017 PRA where Zones 2-7 cleared at \$72/MW-day (the
20 economic threshold was approximately \$26/MW-day); the second was during the
21 2020-2021 PRA when Zone 7 cleared in shortage at CONE. Even during the
22 2015-2016 Planning Resource Auction, when the ACP in LRZ 4 cleared at
23 \$150/MW-day, the economic withholding threshold was \$180/MW-day. MISO is

1 not proposing further mitigation so as to prevent shortage price suppression which
2 could exacerbate potential revenue sufficiency issues. Existing ZRC Offer
3 mitigation measures will be retained, including the threshold for economic
4 withholding which remains set at 10% of CONE (approximately \$25/MW-day)
5 above a default reference level of \$0. Market Participants desiring to offer above
6 the economic withholding threshold will need to request and obtain facility or
7 technology specific reference levels in consultation with the IMM that consider
8 relevant costs per section 64.1.4 of Module D. Such Reference Levels have
9 historically accounted for a small fraction of ZRC Offers in the annual Planning
10 Resource Auctions.

11 **Q. How could the Auction Clearing Price adjustments result in revenue**
12 **sufficiency issues for Market Participants that clear ZRCs in Seasons where**
13 **adjustments occur?**

14 A. Market Participants that obtain facility-specific Reference Levels or are otherwise
15 not subject to the economic withholding provisions of Module D, for example
16 Demand Response, may submit ZRC Offers for individual Seasons up to a cap
17 which will be set at annual CONE divided by the number of days in the Season,
18 approximately \$1,000/MW-day. When an LRZ clears with two or more Seasons
19 in shortage or near shortage conditions, the final ACPs for those Seasons are
20 reduced below the marginal offer (or CONE when short) that was used to clear
21 the auction. As a result, cleared ZRC Offers would exceed the final ACPs.
22 Assuming the cleared ZRC Offers reflect the actual costs associated with the
23 Planning Resource, Market Participants may not recover their costs. This would

1 necessitate a payment or credit to ensure the Resource recovers its costs, but no
2 more, to incentivize it to meet its capacity commitment in all Seasons in which it
3 cleared.

4 **Q. How is MISO proposing to formulate make-whole provisions?**

5 A. In concept, make-whole payments compare market revenues to costs and provide
6 credits to the extent costs exceed revenues. In energy markets, costs are
7 computed based upon resource offers, assuming they reflect the costs of
8 producing energy. ZRC Offers may not reflect the actual costs of providing
9 capacity if a Planning Resource clears in multiple Seasons but its annual costs are
10 compressed into each season's ZRC Offer to ensure recovery if the Resource only
11 clears in a single Season. To account for this, MISO proposes a make-whole
12 provision, defined as the ZRC Offer Revenue Sufficiency Credit, that considers a
13 Resource's revenues from all cleared Seasons and credits a Resource if needed to
14 meet the minimum of the following amounts: (i) the sum of cleared ZRC Offer
15 price segments multiplied by the cleared ZRC Offer Volumes multiplied by the
16 number of days in the Season; (ii) annual CONE; or (iii) the applicable reference
17 level costs for resources that obtained technology or facility-specific Reference
18 Levels for cleared Seasons. This formulation will prevent the ZRC Offer
19 Revenue Sufficiency Credit from contributing to over-recovery of costs.

20 **Q. Who will pay for ZRC Offer Revenue Sufficiency Guarantee Credits and**
21 **how will they be distributed?**

22 A. Charges to fund ZRC Offer Revenue Sufficiency Guarantee Credits will be
23 distributed to Market Participants representing LSEs in the LRZs experiencing

1 shortage or near shortage conditions *pro rata*, based on their respective LSEs’
2 share of PRMR minus the PRMR associated with the Capacity Deficiency Charge
3 within the LRZs during the Seasons where ACPs were reduced. The allocation is
4 similar to the allocation of the Zonal Deliverability Benefit which occurs when an
5 LRZs ACP separates from the systemwide ACP due to limited import or export
6 capability, which will occur whenever LRZs experience shortage or near shortage
7 conditions.

8 **Q. Should ZRC Offer Revenue Sufficiency Guarantee Credits occur frequently?**

9 A. MISO expects that payment of ZRC Offer Revenue Sufficiency Guarantee Credits
10 will be infrequent due to the conditions necessitating the payments that include:

11 (i) LRZs, a group of LRZs, or a Sub-Regional Resource Zone must clear in
12 shortage or near shortage conditions in more than one Season; (ii) ZRC Offers
13 must exceed the final ACP for the applicable LRZs and Seasons; (iii) in order for
14 ZRC Offers to exceed the economic withholding threshold, they must obtain
15 facility-specific reference levels or be excluded from the economic withholding
16 provisions of Module D; and (iv) the Planning Resource’s actual costs associated
17 with its ZRC Offer must exceed auction revenue credits for the Seasons cleared.

18 As noted above, in past PRAs very low volumes of ZRCs have offered above the
19 economic withholding threshold and the PRA has only cleared above the
20 economic withholding threshold twice since the PRA began in 2013.

21 **VI. OUTAGE COORDINATION**

22 **Q. What are the current RAN Phase 1 exemption rules for Generator Planned**
23 **Outages?**

1 A. Under the current RAN Phase 1 generator outage exemption rules, exemptions
2 will be provided if one of the following conditions are met:
3 (1) The Generator Owner or Generator Operator schedules its first Generator
4 Planned Outage 120 days or more in advance of the outage start date and 120
5 days or more beyond the end date of any previously scheduled outages for the
6 unit; (2) Subsequent generator unit outage requests 120 days or more in advance
7 and Generator Owners or Generator Operators Generator Planned Outage less
8 than 120 days in advance and at least 14 days in advance of outage start date.
9 Proposed Generator Planned Outage to occur entirely during a period that the
10 subregion containing the generator unit has an adequate projected margin, at the
11 time the outage is provided to the Transmission Provider. There is adequate
12 margin when the Maintenance Margin is greater than or equal to zero megawatts
13 after subtracting the megawatts of the requested Proposed Generator Planned
14 Outage. The request shall be determined based on highest queued request; or (3)
15 Generator Owner or Generator Operator reschedules its Generator Planned
16 Outage at the Transmission Provider's request, including outages submitted less
17 than 14 days in advance of the start date.

18 **Q. What is MISO's proposal for exemption of Generator Planned Outages?**

19 A. MISO worked with stakeholders to develop an exemption process that integrates
20 with the tiered accreditation calculations in Schedule 53. The three levels are:
21 Full exemption for Generator Planned Outages (from Tier 1 and Tier 2 SAC
22 calculations in Schedule 53), partial exemption (only exempt in Tier 1 SAC
23 calculations), and no exemption. The following chart illustrates the proposed

- 1 exemption requirements, please note that Maintenance Margin is currently
- 2 calculated and posted for MISO's north, central, and south sub-regions separately:

Generator Outage Submission Criteria	Maintenance Margin ≥ 0 for duration of outage	Maintenance Margin < 0 for any day in the duration of outage
>120 days prior to outage start date, and >120 days from end of previous outage for unit	Exempt Tier 1 & 2	Exempt Tier 1 Only
>120 days Prior to Outage Start date and <120 days from end of Previous outage for unit or Outage submitted between 31-119 days Prior to outage start date	Exempt Tier 1 Only	No Exemption
14-30 days prior to outage start date and passes No Harm Test	Exempt Tier 1 Only	No Exemption
Outage moved per MISO request	Exempt Tier 1 & 2 (Weather, forced outages, other conditions in BPM-008)	Exempt Tier 1 & 2 (Weather, forced outages, other conditions in BPM-008) at Transmission Provider's discretion

3

- 4 A more detailed description of how to procure Generator Planned Outage
- 5 Exemptions are provided in proposed Schedule 53.

6 **Q. What is the No Harm Test?**

- 7 A. No harm tests will include, but will not be limited to outage approval, compliance
- 8 with all applicable operation guides, review of possible conflicting outages or
- 9 system conditions, and forecasts of system capacity (Maintenance Margin,
- 10 Multiday Operational Margin, 30-day margin). It will also include criteria
- 11 outlined in the Business Practices Manual for Outage Coordination, specifically:
- 12 the ability to maintain voltage required by nuclear generation resources, or to

1 meet any other nuclear plant interface requirements; the ability to maintain the
2 Transmission System within system operating limits using normal (non-
3 emergency) operating procedures or restore the Transmission System to normal
4 operating conditions following a single contingency with the use of normal (non-
5 emergency) operating procedures; or does not have the potential for credible
6 contingencies to significantly affect Transmission System reliability of
7 metropolitan areas.

8 **Q. How will MISO treat planned outages that were submitted before this**
9 **proposal goes into effect?**

10 A. MISO proposes a transition with a bright line distinction based on whether a
11 planned outage is scheduled to start prior to September 1, 2022. Planned outages
12 submitted since spring 2019 are coded as exempt or not in the Control Room
13 Operations Window (“CROW”) under RAN Phase 1. Where coded exempt, those
14 resources will be treated as fully exempt for Tier 1 & 2 in the calculations
15 proscribed in Schedule 53 even though they may not have met both of the primary
16 requirements of (1) being submitted 120 days or greater in advance and (2)
17 leaving positive Maintenance Margin in the subregion for the duration of the
18 outage. MISO believes this approach is appropriate as it has been highlighting the
19 risks to capacity sufficiency from correlated planned outages since September
20 2017 and ongoing efforts to encourage sufficient outage coordination and improve
21 tools and processes have greatly reduced the frequency of MaxGens declared in
22 Spring and Fall since RAN Phase 1 went into effect.

23 **Q. Describe MISO’s authority related to coordination of generator outages.**

1 A. Under the Tariff (section 38.1.1.e titled “Scope of Services”) MISO is required to
2 “Coordinate maintenance schedules for Generation Resources and approve,
3 coordinate, and reschedule as necessary Planned Transmission Outages operated
4 within the Transmission Provider Region.” MISO does not have the authority to
5 deny generation outages, but the existing tariff does allow MISO’s accreditation
6 of Planning Resources to be reduced based on insufficient coordination of
7 Generator Planned Outages.

8 **Q. What changes are being proposed to MISO’s generation outage exemption**
9 **rules under the proposal?**

10 A. Given the strong correlation between high outage levels and MaxGens,
11 modifications to MISO’s outage coordination processes and procedures will be
12 implemented to enhance the determination of SAC for Resources subject to
13 Schedule 53.

14 **Q. What changes are being proposed to the rules governing the exemption of**
15 **Generator Planned Outages for accreditation purposes?**

16 A. Outage exemptions will usually be given at the time of outage submittal review or
17 in response to a CROW ticket change request. The purpose of the exemption is to
18 ensure that a Resource’s accreditation is not negatively impacted by unavailability
19 associated with a sufficiently coordinated outage. Exemptions are granted based
20 outage lead time criteria and adequate Maintenance Margin as outlined above. A
21 generation outage ticket submitted into CROW will be reviewed to determine if
22 such outage is exempt from accreditation impacts under Schedule 53. Outage
23 approvals and exemptions have separate purposes and criteria but bridge the gap

1 between the planning and operational horizons. As is the case today, approvals
2 will be based on reliability analysis in the Outage Coordination process. The
3 outage will receive exemption from the SAC calculation if it meets the criteria
4 outlined above. It should be noted that the exemption status of an outage does not
5 impact whether it is “approved” in the Outage Coordination processes.
6 Outage exemptions will usually be given at the time of outage submittal review or
7 in response to a CROW ticket change request. The purpose of the exemption is to
8 ensure that resources are not penalized for unavailability for a sufficiently
9 coordinated outage. The criteria for exemptions are outage lead time and
10 adequate Maintenance Margin.

11 **VII. MARKET MONITORING AND MITIGATION**

12 **Q. Will MISO’s current market monitoring and mitigation provisions be**
13 **modified to address market power concerns in the new seasonal construct?**

14 A. Yes, current market monitoring and mitigation provisions have been modified in
15 the submitted tariff redlines and substantive enhancements regarding physical and
16 economic withholding are discussed below.

17 **Q. Please describe how physical withholding of Zonal Resource Credit offers**
18 **into the PRA will be affected.**

19 A. The move to seasonal auctions calls for minor modifications that ensure these
20 same protections continue to work going forward. Primarily, it is the exclusions
21 from auction participation in Section 64.1.1.g of Module D that need to be
22 adapted for a seasonal approach. In one more substantive change in that section,
23 MISO proposes removing the preclusion from participation for a resource that

1 expects to be on outage for greater than 90 of the first 120 days of the Planning
2 Year and replacing that with a provision that says an Market Participant with a
3 resource that has submitted an outage for greater than 31 days of a Season can ask
4 the IMM for a determination ahead of the auction allowing it to forego offering
5 excess ZRCs from the resource without being deemed to have engaged in
6 Physical Withholding.

7 **Q. Please explain about how Economic Withholding will be affected.**

8 A. MISO is not proposing to change the initial reference level, economic withholding
9 threshold. The initial reference level remains at \$0 and the economic withholding
10 threshold is 10% of CONE above \$0, which currently would make ~\$25/MW-day
11 the effective offer cap unless an MP gets a facility-specific Reference Level or
12 uses Default Technology Specific Avoidable Costs at which point it becomes the
13 economic withholding threshold for the resource. It is expected that more
14 resources will request facility-specific Reference Levels or use Default
15 Technology Specific Avoidable Costs to help ensure they can cover their costs
16 when they might only clear for one Season instead of the full Planning Year under
17 the current construct.

18 **Q. Do you believe the proposed enhancements are just and reasonable changes**
19 **to the MISO Tariff?**

20 A. Yes. For the reasons set forth above and in the supporting testimonies of Messrs.
21 Wright and Smith, the proposal set forth in this filing is both just and reasonable
22 and is needed now to help ensure the continued reliability of the MISO Region
23 through enhancements to MISO's Resource Adequacy construct. For this reason,

1 MISO urges the Commission to accept the proposed Tariff enhancements to be
2 effective for the 2023 – 2024 PRA.

3 **Q. Does this conclude your testimony?**

4 A. Yes.

Affidavit of Shawn McFarlane

COUNTY OF HAMILTON)

)

STATE OF INDIANA)

Shawn McFarlane, being duly sworn, deposes and states that he prepared the Prepared Direct Testimony of Shawn McFarlane, and the statements contained therein are true and correct to the best of his knowledge and belief.

/s/ Shawn McFarlane

Shawn McFarlane

SUBSCRIBED AND SWORN BEFORE ME, this 30th day of November, 2021.

My Commission Expires:

My County of Residence:

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Midcontinent	)	Order No. 202-26-29
Independent System Operator and	)	
Northern Indiana Public Service	)	
Company LLC	)	

Federal Power Act Section 202(c)	)	
Emergency Order: Midcontinent	)	Order No. 202-26-30
Independent System Operator and	)	
CenterPoint Energy Indiana South	)	

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 199
MISO Winter Storm Fern Summary



Overview of Winter Storm Fern

Reliability Subcommittee
February 17, 2026

Executive Summary



- Winter Storm Fern brought extreme cold, snow and ice across the MISO footprint, which created operational challenges including forecasting errors, unit availability, and low wind production
- To maintain reliability, two Maximum Generation Events - Step 2c were declared on January 24 allowing MISO access to generation unit emergency ranges, load modifying resource curtailments, and emergency power purchases
- MISO is actively engaging in solutions to address the challenges that arose during the event

Proactive and on-going planning prepared MISO for this winter storm

MISO regularly coordinates with our neighbors during events and normal operations

SYSTEM TOPOLOGY

- Highly inter-connected grid across 15 states and Manitoba
- Diverse generation mix
- Relationships with seams partners

ON-GOING

- Coordinated Seasonal Assessments (Winter)
- Winter Readiness Workshops
- Emergency Procedure Drills

PRE-EVENT

- Issued Informational Advisories & Cold Weather Alert
- Daily coordination with neighbors
- Declared Conservative Operations

EVENT

January 24, 2026

- Max Generation Event Step 2c – North and Central Regions
 - Emergency Ranges
 - Utilized LMRs
 - Emergency Power Purchase from PJM

January 26, 2026

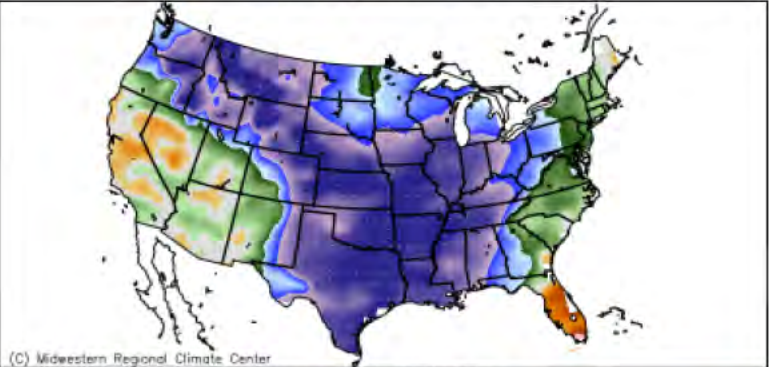
- Capacity Advisory – North and Central Regions

While all occurring in January over the last three years, each winter event has unique characteristics that require different actions

WINTER STORM HEATHER

January 13-17, 2024

Average Temperature (°F): Departure from Mean
January 16, 2024



(C) Midwestern Regional Climate Center
Mean period is 1991–2020.

System Peak Load (January 16, 2024)

105 GW

Incremental Unplanned Outages

4 GW

Scheduled Load Modifying Resources*

0 MW

RDT Max Flow & Direction

2.6 GW N-S

Average Daily Wind Generation

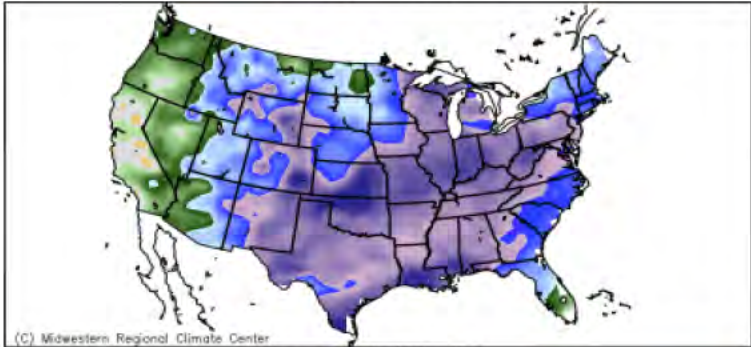
20.0 GW

Precipitation: Moderate snowfall across MISO's South and Central regions

WINTER STORM ENZO

January 18-22, 2025

Average Temperature (°F): Departure from Mean
January 21, 2025



(C) Midwestern Regional Climate Center
Mean period is 1991–2020.

System Peak Load (January 21, 2025)

107 GW

Incremental Unplanned Outages

10 GW

Scheduled Load Modifying Resources*

1.2 GW

RDT Max Flow & Direction

2.7 GW N-S

Average Daily Wind Generation

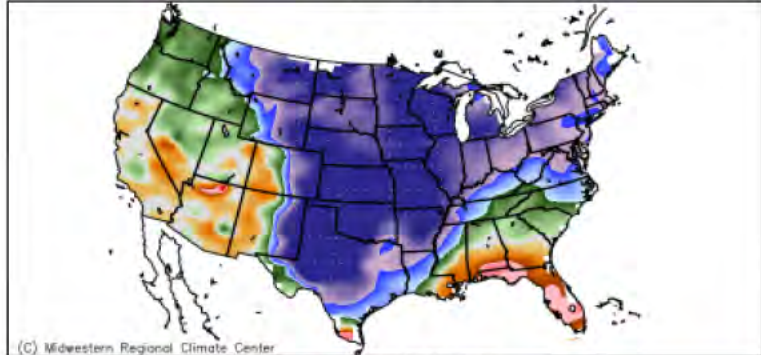
15.4 GW

Precipitation: Modest snowfall across MISO's North and Central regions

WINTER STORM FERN

January 22-27, 2026

Average Temperature (°F): Departure from Mean
January 24, 2026



(C) Midwestern Regional Climate Center
Mean period is 1991–2020.

System Peak Load (January 27, 2026)

105 GW

Incremental Unplanned Outages

6 GW

Scheduled Load Modifying Resources

2.0 GW

RDT Max Flow & Direction

4.0 GW S-N

Average Daily Wind Generation

3.1 GW

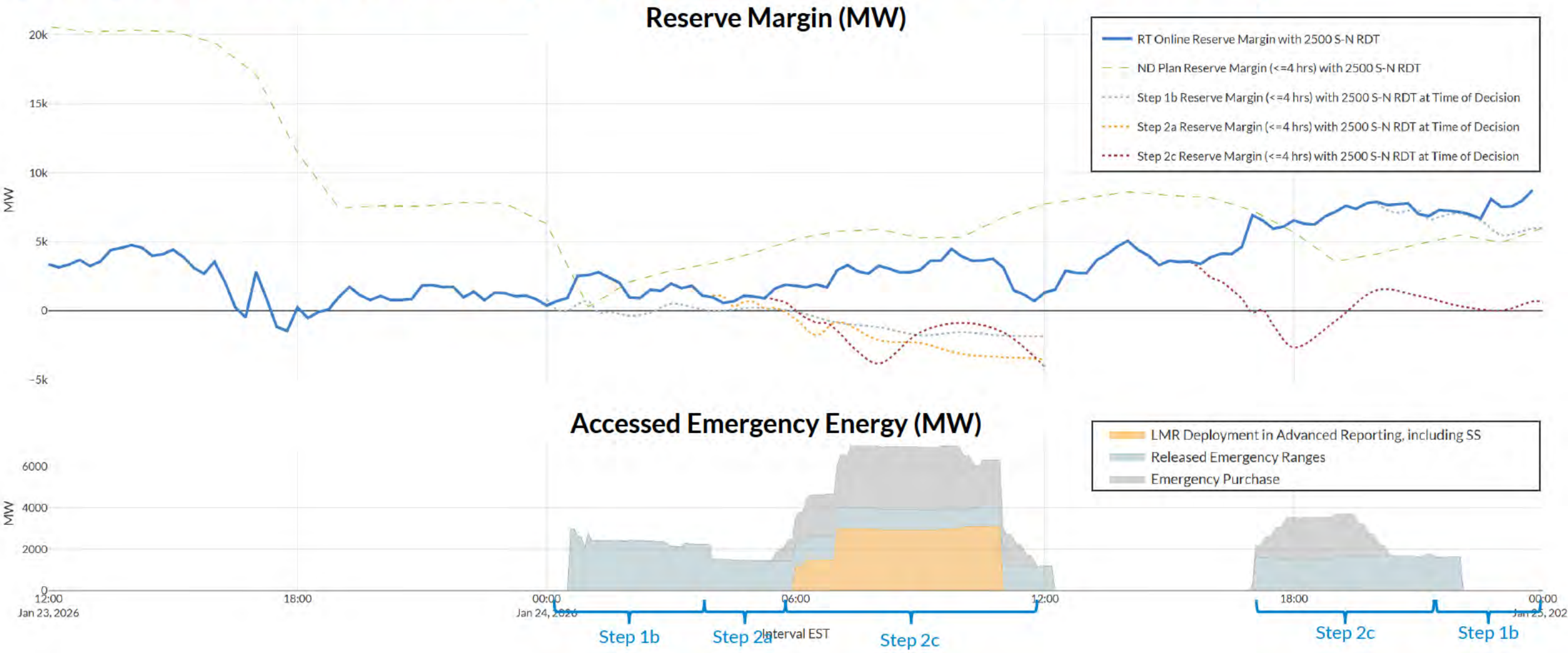
Precipitation: Significant snowfall across MISO's South and Central regions, significant icing in the South region

Load Modifying Resources requested for the peak load hour for the noted storm time period

4



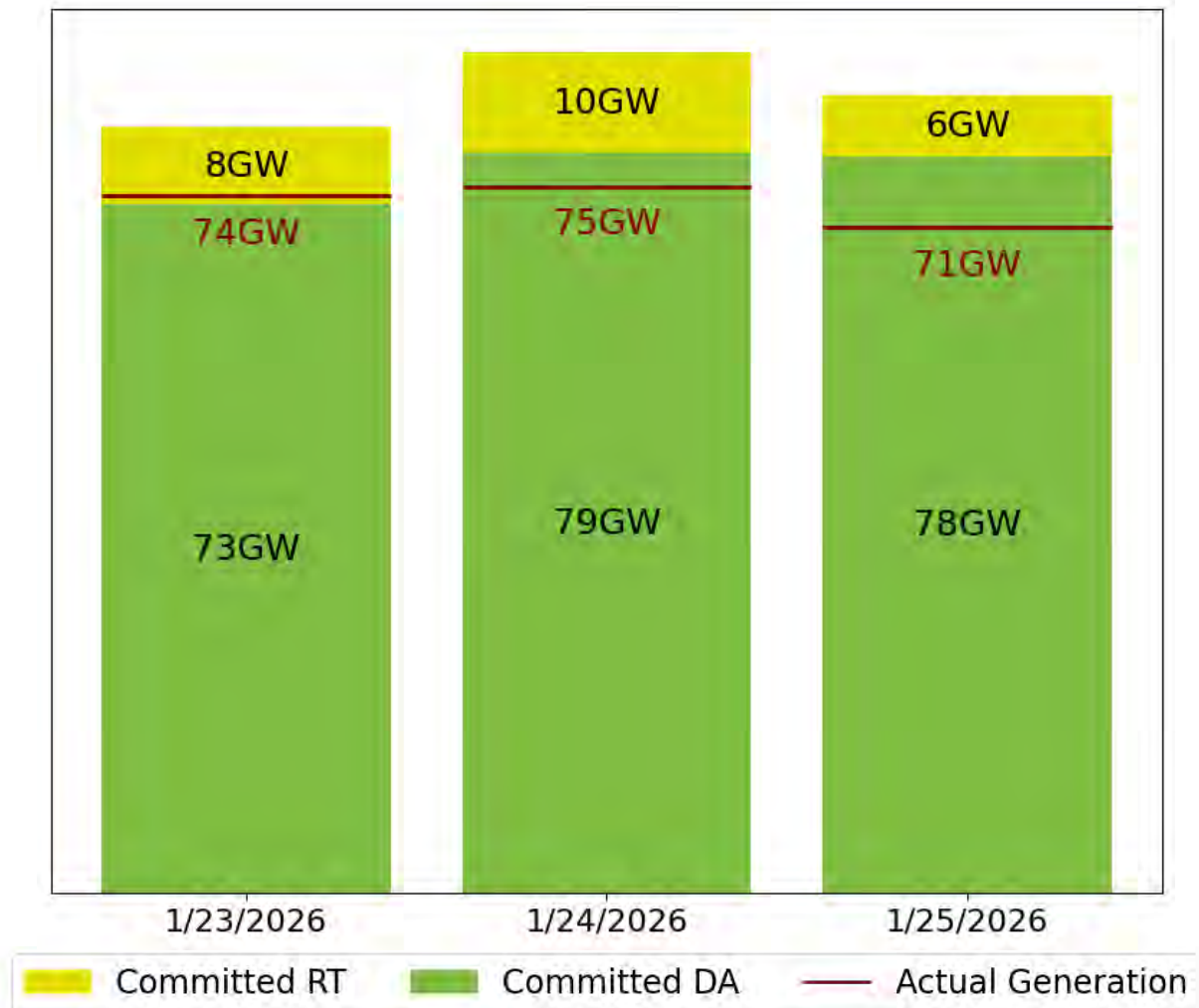
Persistent negative capacity margins in the North and Central regions on January 24 prompted MISO to take emergency actions to maintain system reliability



Event step times are approximate, for exact times see slide 11 in the appendix
RT = Real Time and ND = Next Day

Significant unplanned outages caused by the extreme cold contributed to the need for MISO to commit all available resources in real time

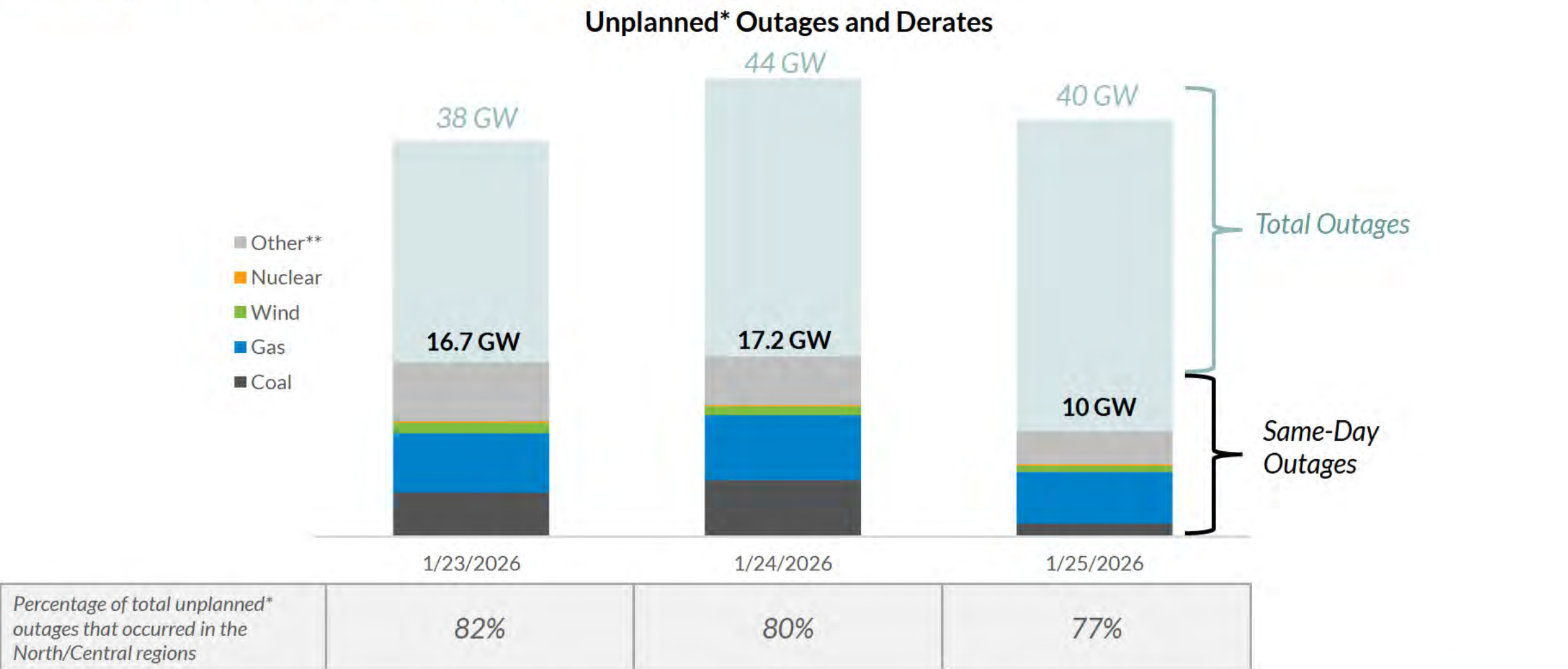
Daily Committed Thermal Unit Capacity in DART & Actual Generation at Peak Hour



Extended Combustion Turbine (CTs) lead times hindered real-time commitments

- In the North and Central regions 29 CTs increased their start times significantly on January 23
- 13 of those remained under the 24-hour notification threshold to maintain maximum accreditation value

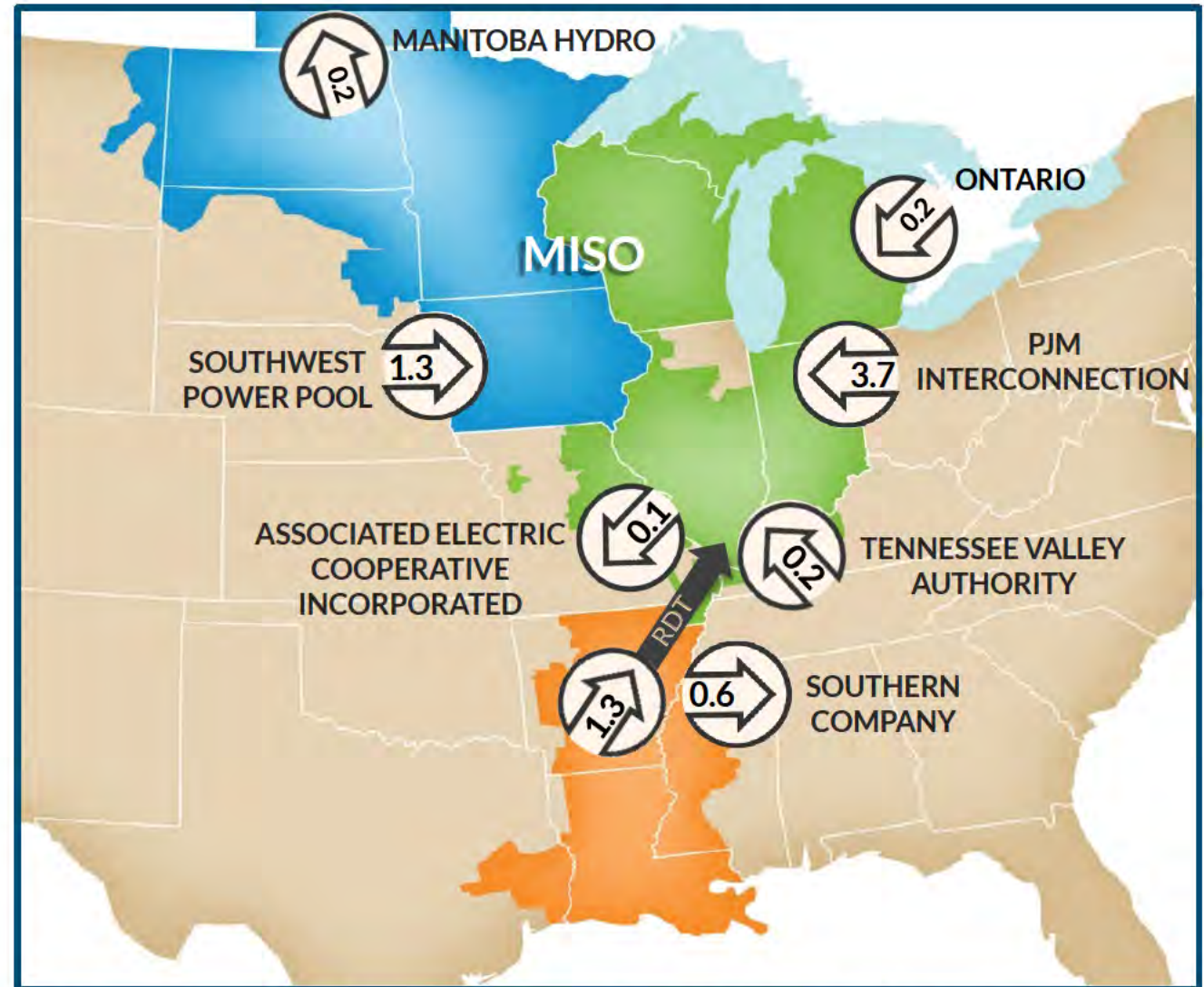
MISO experienced significant unplanned outages due to the extreme cold mostly in the North and Central Region



Emergency prices were not published for eleven hours on January 24 due to technical issues; as a result, prices did not reflect emergency conditions and imports were not properly incentivized

Imports from PJM were driven by emergency energy purchases

Average Net Scheduled Interchange (GW) January 24, 2026



RDT = Regional Directional Transfer, which has a North-South limit of 3.0 GW and South-North limit of 2.5 GW

Challenges that impacted operations during Winter Storm Fern are already being addressed with solutions



Proactive Communication

MISO coordinated with members to maximize transmission and generation availability



Staffing Support

Extra operators, including dual-qualified operators, ensured MISO had the experienced personnel needed



Coordination with Neighbors

PJM provided emergency energy that was key to addressing capacity concerns

LESSONS LEARNED

- **Tailored Operating Instruction:** There was a lack of clarity in operating instruction regarding public appeals; enhanced functionality in Operator Interface will be implemented by this summer
- **Pricing Fix** - Ex-Post LMPs were not calculated or published for ~11 hours due to a software issue; a fix was implemented on February 5, 2026
- **Reserve Procurement and Deliverability** - Reserves offered into the market were stranded in the south but Look Ahead Commit (LAC) could not differentiate; enhancement will be delivered this year
- **Uncertainty Forecasting and Peak Hour Planning** - Enhancements needed to improve uncertainty forecasting model, and we need to move away from peak hour planning and assess the operating plan across all hours of the operating day
- **Emergency Pricing** - Emergency prices were observed in the non-emergency South region; cause TBD but needs to be addressed

Appendix

Sequencing of alert, warning and events during winter storm Fern

ALERTS

Cold Weather Alert (System Wide)

Jan 23, 00:00 EST – Feb 01, 23:59 EST

Conservative Operations (System Wide)

Jan 23, 20:00 EST – Jan 29, 23:59 EST

Conservative Operations (MISO South)

Jan 30, 00:01 EST – Feb 01, 23:59 EST

WARNING

Capacity Advisory (North and Central)

Jan 29, 00:00 EST – Jan 29, 23:59 EST

Max Generation Warning (North and Central)

Jan 24, 12:00 EST – Jan 24, 17:00 EST

EVENTS

Max Gen Event Step 1b (North and Central)

Jan 24, 00:30 EST – Jan 24, 04:36 EST

Max Gen Event Step 2a (North and Central)

Jan 24, 04:36 EST – Jan 24, 06:01 EST

Max Gen Event Step 2c (North and Central)

Jan 24, 06:01 EST – Jan 24, 12:00 EST

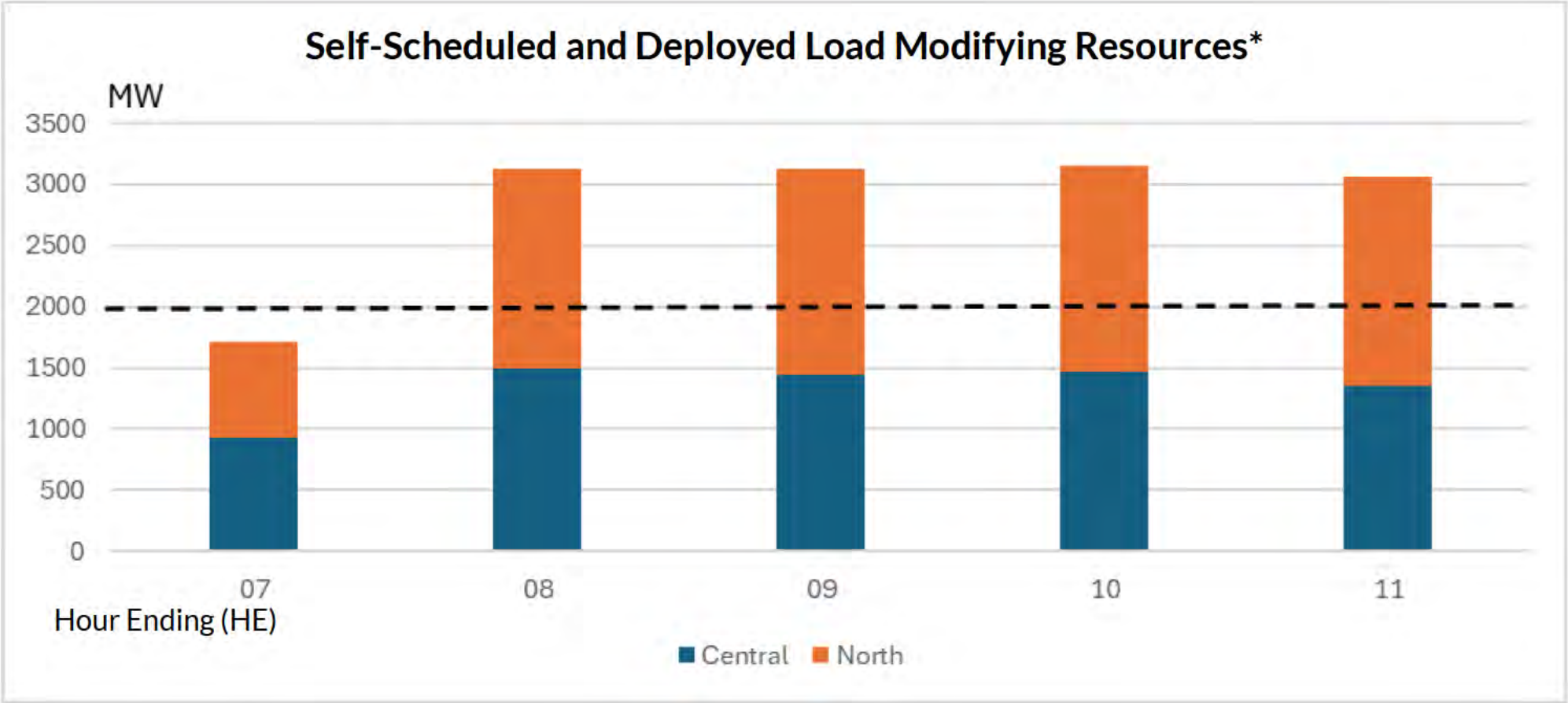
Max Gen Event Step 2c (North and Central)

Jan 24, 17:00 EST – Jan 24, 21:00 EST

Max Gen Event Step 1b (North and Central)

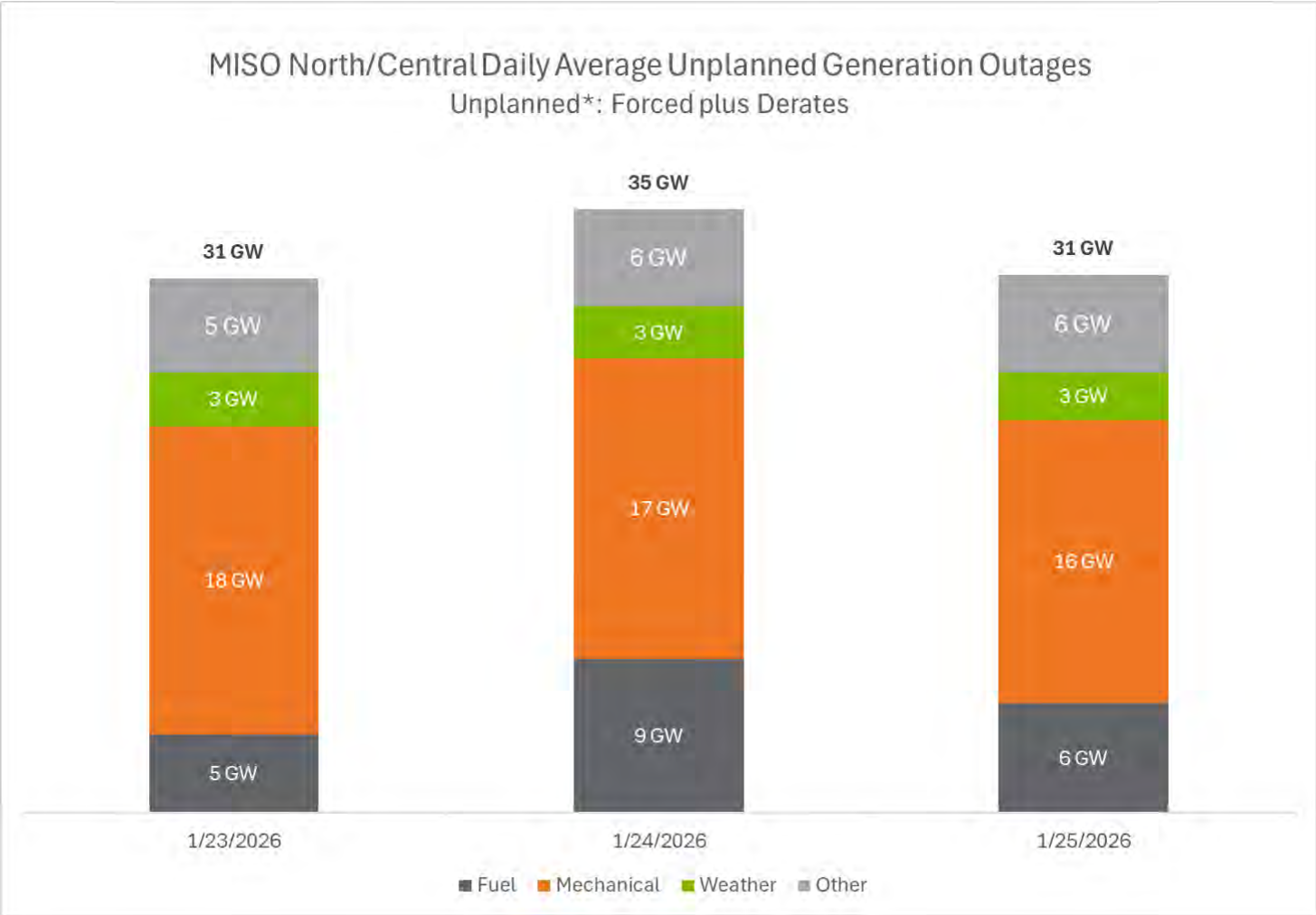
Jan 24, 21:00 EST – Jan 24, 23:59 EST

As part of the EEA2 declaration, MISO deployed ~2 GW of Load Modifying Resources in addition to the self-scheduled amount in the North and Central regions



*MP Acknowledgement of MISO scheduling instructions

MISO experienced an increase of unplanned and derated outages due to fuel-related issues in the North and Central regions



**Unplanned = forced outages and derates, Charts reflect data in the CROW outage system on January 26, 2026, Wind often reported as derated over the time period*

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Midcontinent	)	Order No. 202-26-29
Independent System Operator and	)	
Northern Indiana Public Service	)	
Company LLC	)	

Federal Power Act Section 202(c)	)	
Emergency Order: Midcontinent	)	Order No. 202-26-30
Independent System Operator and	)	
CenterPoint Energy Indiana South	)	

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 200
CenterPoint Culley Discovery Response

Despite references in this document to the presence of confidential information, all confidential information has been redacted by Public Interest Organizations, and the document's sponsor has confirmed the redacted document contains no confidential information.

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED APPLICATION OF SOUTHERN INDIANA GAS AND ELECTRIC COMPANY D/B/A CENTERPOINT ENERGY INDIANA SOUTH FOR (1) ISSUANCE OF AND A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR A FEDERALLY MANDATED CULLEY 202(c) COMPLIANCE PROJECT; (2) APPROVAL OF THE PROJECTED FEDERALLY MANDATED COSTS ASSOCIATED WITH THE CULLEY 202(c) COMPLIANCE PROJECT; (3) AUTHORITY FOR THE TIMELY RECOVERY OF 80% OF THE FEDERALLY MANDATED COSTS THROUGH CEI SOUTH’S ENVIRONMENTAL COST ADJUSTMENT MECHANISM (“ECA MECHANISM”); (4) AUTHORITY TO DEFER 20% OF THE FEDERALLY MANDATED COSTS FOR RECOVERY IN CEI SOUTH’S NEXT GENERAL RATE CASE; (5) APPROVAL OF SPECIFIC RATEMAKING AND ACCOUNTING TREATMENT; (6) APPROVAL TO AMORTIZE THE CULLEY 202(c) COMPLIANCE PROJECT COSTS; (7) APPROVAL OF ONGOING REVIEW OF THE CULLEY 202(c) COMPLIANCE PROJECT; AND (8) APPROVAL TO ADJUST PETITIONER’S AUTHORIZED NET OPERATING INCOME TO REFLECT ANY APPROVED EARNINGS ASSOCIATED WITH THE CULLEY 202(C) COMPLIANCE PROJECT FOR PURPOSES OF IND. CODE § 8-1-2-42(d)(3); ALL PURSUANT TO IND. CODE § 8-1-8.4-1 *et seq.*, § 8-1-2-19, § 8-1-2-23, AND § 8-1-2-42.

CAUSE NO. 46350

**CENTERPOINT ENERGY INDIANA SOUTH’S RESPONSE TO
CAC’S SECOND SET OF DATA REQUESTS**

Southern Indiana Gas & Electric Company d/b/a CenterPoint Energy Indiana South (“CEI South”) pursuant to 170 IAC 1-1.1-16 and the discovery provisions of Rules 26 through 37 of the Indiana Rules of Trial Procedure, by its counsel, hereby submits the following Objections and Responses to the Citizen’s Action Coalition’s (“CAC”) Second Set of Data Requests dated June 25, 2026 (“Requests”).

General Objections

All of the following General Objections are incorporated by reference in the response to each of the Requests:

1. The responses provided to the Requests have been prepared pursuant to a reasonable and diligent investigation and search conducted in connection with the Requests in those areas where information is expected to be found. To the extent the Requests purport to require more than a reasonable

and diligent investigation and search, CEI South objects on grounds that they include an undue burden or unreasonable expense.

2. CEI South objects to the Requests to the extent they seek documents or information which are not relevant to the subject matter of this proceeding and which are not reasonably calculated to lead to the discovery of admissible evidence.

3. CEI South objects to the Requests to the extent they seek responses and information from individuals and entities who are not parties to this proceeding and to the extent they request the production of information and documents not presently in CEI South's possession, custody or control. CEI South further objects to the Requests to the extent they are (i) vague and ambiguous as to the individuals and entities to whom the Request refer, or (ii) overbroad and not reasonably calculated to lead to the discovery of relevant or admissible evidence.

4. CEI South objects to the Requests to the extent they seek an analysis, calculation, or compilation which has not already been performed and which CEI South objects to performing.

5. CEI South objects to the Requests to the extent they are vague and ambiguous and provide no basis from which CEI South can determine what information is sought.

6. CEI South objects to the Requests to the extent they seek information outside the scope of this proceeding, and as such, the Requests seek information not reasonably calculated to lead to the discovery of relevant or admissible evidence.

7. CEI South objects to the extent the Requests purport to require production of (a) information in a particular format; (b) multiple copies of the same document; (c) additional copies of the same document merely because alterations, notes, comments, or other material appear thereon when such other material is not material or relevant; and (d) copies of the same information in multiple formats on the grounds that it is irrelevant, overbroad, unreasonably burdensome and not required by the Commission rules and inconsistent with practice in Commission proceedings.

8. CEI South objects to the Requests to the extent they solicit copies of voluminous documents.

9. CEI South objects to the Requests to the extent the discovery sought is unreasonably cumulative or duplicative; or is obtainable from some other source that is more convenient, less burdensome, or less expensive.

10. CEI South objects to the Requests to the extent the burden or expense of the proposed discovery outweighs its likely benefit, taking into account the needs of the case, the amount in controversy, the parties' resources, the importance of the issues at stake in litigation, and the importance of the proposed discovery in resolving the issues.

11. CEI South objects to the Request on the grounds that it is overbroad, unreasonably burdensome and seeks information that is largely irrelevant to the subject matter of this proceeding.

12. CEI South objects to the Requests to the extent they seek information that is confidential, proprietary, competitively sensitive and/or trade secret.

13. The responses constitute the corporate responses of CEI South and contain information gathered from a variety of sources. CEI South objects to the Requests to the extent they request identification of and personal information about all persons who participated in responding to each data request on the grounds that it is overbroad, unreasonably burdensome and irrelevant given the nature and scope of the requests and the many people who may be consulted about them. CEI South further objects to the Requests to the extent they purport to require identification of a witness who can answer questions regarding the substance of or origination of information supplied in each response on the ground that CEI South has no obligation to call witnesses to testify as to information provided in discovery.

14. CEI South objects to the Requests to the extent they seek information that is subject to the attorney-client, work product, settlement negotiation or other applicable privileges. CEI South further objects to the Requests to the extent they purport to require the creation of a privilege log on the grounds that given the extremely expedited and informal nature of discovery in this proceeding, contemporaneous privilege logs are inappropriate. CEI South objects to the Requests on the grounds they are unreasonably burdensome, overbroad, inconsistent with discovery practices in Commission proceedings and inconsistent with the informal discovery process applicable to this proceeding.

15. CEI South assumes no obligation to supplement these responses except to the extent required by Ind. Tr. R. 26(E) (1) and (2) and objects to the extent the instructions and/or Requests purport to impose any greater obligation. CEI South denies that Ind. Tr. R. 26(E)(3) applies to the Requests.

Subject to and without waiver of the general and specific objections set forth herein, CEI South responds to the Requests in the manner set forth below.

Confidential information in green

Data Requests – Set 02

2-1. Please provide the following information for Culley Unit 2:

- a) hourly net generation since December 23, 2025 and its MISO dispatch status during this time (e.g., Must-Run, Economic, Outage, etc.);
- b) total costs and revenues since December 23, 2025;
- c) identification of each forced outage, when it occurred, and for how long, since December 23, 2025;
- d) the anticipated timing and purpose of any current unforced outages or planned outages later this year; and
- e) the total capital investment and maintenance expense expected to be made from December 23, 2025, through the end of the current 202(c) order period and through the end of 2026 assuming 202(c) order extensions through this time.

Objection: Petitioner objects to the Request on grounds and to the extent the Request seeks information that is trade secret or other proprietary, confidential, and competitively sensitive business information of Petitioner, its customers, or its vendors. Petitioner has made reasonable efforts to maintain the confidentiality of this information. Such information has independent economic value and disclosure of the requested information would cause an identifiable harm to Petitioner, its customers, or its vendors. The responses are "trade secret" under law (Ind. Code § 24-2-3-2) and entitled to protection against disclosure. See also Indiana Trial Rule 26(C)(7). All responses containing designated confidential information are being provided pursuant to non-disclosure agreements between Petitioner and the receiving parties.

Petitioner further objects to subpart e) of this Request on the separate and independent grounds and to the extent that it assumes Petitioner has capitalized costs associated with compliance with the DOE 202(c) orders as incorrect in its premise. Petitioner is tracking and deferring all costs associated with compliance but has not, to date, capitalized such costs.

Subject to and without waiving the foregoing objection, CEI South provides the following response:

Response:

- a) See the attached files marked 46350_CEIS_CAC 2-1(a) (CONFIDENTIAL)_Culley 2 gen data 12-13-25.csv and 46350_CEIS_CAC 2.1(a) (CONFIDENTIAL)_Culley 2 hourly DA-RT commit status.xlsx.
- b) Through May 31, 2026 costs presently deferred total [REDACTED] offset partially by total revenues of [REDACTED]. Note that because CEI South has not yet filed for cost recovery through the FERC, these numbers are preliminary, have not yet been finalized or fully reviewed and therefore remain subject to change.
- c) See table below:

Forced Outages	Days	Issue	Result
17-Jan-26	6	Turbine/Generator Issues	Generator repairs
27-Jan-26	2	Boiler Tube Leaks	Repaired leaks
25-Feb-26	2	Boiler Tube Leaks	Repaired leaks & Generator Issue Resolved
21-Mar-26	2	Boiler Tube Leaks	Repaired leaks
16-May-26	1	Boiler Tube Leaks	Repaired leaks

- d) CEI South completed a planned outage to perform inspections, testing, and maintenance to maintain the unit's availability for MISO dispatch, including high-energy piping inspections, boiler maintenance, transformer testing, turbine valve inspections, and other maintenance of critical plant equipment. CEI South does not currently anticipate any additional planned outages for the remainder of 2026.
- e) Maintenance expenses are estimated to be [REDACTED] through September 19, 2026, and [REDACTED] through December 31, 2026.

Attachments:

- 46350_CEIS_CAC 2-1(a) (CONFIDENTIAL)_Culley 2 gen data 12-13-25.csv
- 46350_CEIS_CAC 2.1(a) (CONFIDENTIAL)_Culley 2 hourly DA-RT commit status.xlsx

Dated: July 6, 2026

As to objections only,



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Jeffery A. Earl, Atty. No. 27821-64

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Attorneys for CEI South Southern Indiana Gas &
Electric Company d/b/a/ CenterPoint Energy Indiana
South

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Midcontinent	)	Order No. 202-26-29
Independent System Operator and	)	
Northern Indiana Public Service	)	
Company LLC	)	

Federal Power Act Section 202(c)	)	
Emergency Order: Midcontinent	)	Order No. 202-26-30
Independent System Operator and	)	
CenterPoint Energy Indiana South	)	

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 201
EPA CAMPD Data on Schahfer and Culley Output
from Jan. 20 through Jan. 31, 2026

1

State		Facility Name	Facility Unit ID	Associated	De a	Hour	Gross Load (MW)	Steam Load (100 lbs/hr)	SO2		CO2		CO		NOx		Rate		Heat Input (MMBtu/hr)	Primary Fuel	Secondary Fuel	Unit type	SO2 Controls	NOx Controls	PM Controls	H2 Controls	Program
									Mass Rate (lb/hr)	Rate (lb/hr)	Mass Rate (lb/hr)	Rate (lb/hr)	Mass Rate (lb/hr)	Rate (lb/hr)	Mass Rate (lb/hr)	Rate (lb/hr)	Mass Rate (lb/hr)	Rate (lb/hr)									
N	F	FB City Generating Station	1012	2 C2603.MS2	12/26/28	0	1	52	0	MEASURE	0.2 CALC	121 MEASURE	0.103 CALC	253.8 MEASURE	0.2 CALC	1179	0.3 CALC	1187	0.3 CALC	D	bottom water - ised boi	Well Limesone	NOx Burner Techology (Dry Bottom only)isue Catalytic Reduction	Ectrosta is Precipitator	APP.CINQX.CS2603E.CS26031	MATS	
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