BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

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

Exhibit 1
December Schahfer Order

Order No. 202-25-12

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

BACKGROUND

The 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 units and two coal-fired 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 are both slated to cease operations in December 2025.[4]

EMERGENCY SITUATION

Midcontinent Independent System Operator, Inc.'s (MISO) 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.[5] MISO justified this revision by explaining that "Reliability risks associated with Resource Adequacy have shifted from 'Summer only' to a year-round concern."[6] MISO noted that over 60% of all

[1] 16 U.S.C. § 824a(c).
[2] 42 U.S.C. § 7151(b).
[3] U.S. Energy Information Administration, Form EIA-860, Schedule 3: Generator Data (2024), https://www.eia.gov/electricity/data/eia860/.
[4] As coal-fired facilities, it would be difficult for the Schahfer Units 17 and 18 to resume operations once they have been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30-60 days to repair if a unit comes offline. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. Further, if Schahfer were to begin disassembling the plant or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist.
[5] *Midcontinent Independent System Operator, Inc.,* FERC Docket No. ER22-495-000 (Nov. 30, 2021). This request was approved by FERC on August 31, 2022. *See Midcontinent Independent System Operator, Inc.*, 180 FERC ¶ 61,141 (2022).
[6] MISO Transmittal Letter at 3, FERC Docket No. ER22-495-000 (Nov. 30, 2021).

"MaxGen" events (events when MISO initiates emergency procedures because of concerns over the adequacy of available generation) occurred outside of the summer season.[7]

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."[8] 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 2023/24 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 that the risk of loss of load in the winter and spring seasons, although not as high as in the summer or fall, will nevertheless increase over time.[9]

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

> Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region's historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.[11]

These MISO studies indicate that the emergency conditions caused by the loss of generation capacity in MISO extend past the summer season. The evidence indicates that there is also a potential longer term resource adequacy emergency in MISO.

In its 2024 Long-Term Reliability Assessment (LTRA), the North American Electric Reliability Corporation (NERC) notes that the MISO assessment area 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."[12]

When MISO reported the results of its PRA for the 2025-26 Planning Year, it noted that "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources" in the northern and central zones, which include Indiana.[13]

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[7] *Id.* at 3-4.
[8] MISO, *Attributes Roadmap*, at 3 (Dec. 2023), https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf.
[9] *Id.* at 11.
[10] MISO, *MISO's Response to the Reliability Imperative* (Updated February 2024), https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf.
[11] *Id.* at 12.
[12] *NERC 2024 Long-Term Reliability Assessment*, at 13 (December 2024, corrected July 11, 2025), https://www.nerc.com/globalassets/our-work/assessments/2024-ltra_corrected_july_2025.pdf.
[13] MISO, *Planning Resource Auction: Results for Planning Year 2025-26*, at 13 (April 2025), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf.

On June 6, 2025, the Organization of MISO States (OMS) and MISO issued the results of their survey, which has been conducted annually for many years to determine the degree to which expected capacity resources satisfy planning reserve margin requirements.[14] The 2025 Survey presented projections of resource adequacy for the summer of 2026 and subsequent years. Although the survey projected a potential capacity surplus for the summer of 2026, it also projected that at least 3.1 GW of additional generation capacity beyond currently committed generation capacity must be added to meet the projected planning reserve margin.[15] The 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.[16] Similar results were projected for MISO's winter seasons, with a small surplus of generation capacity in 2026, followed by increasing deficits the following four years.[17]

The primary reasons for these projected deficits also are shown on the OMS-MISO survey. Large quantities 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.[18] 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.[19]

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.[20] 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 away, and are provided an additional three-year grace period to commence commercial operations.[21] 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.[22] Consequently, it is not at all clear that the new ERAS process will result in the addition of new capacity in the next few years.

More broadly, executive orders issued by President Donald J. Trump on January 20, 2025 and April 8, 2025, underscored the dire energy challenges facing the Nation due to growing

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[14] OMS and MISO, *OMS-MISO Survey Results* (Updated June 6, 2025), https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf.

[15] *Id.* at 2.

[16] *Id.* at 7.

[17] *Id.* at 9.

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

[19] *Id*.

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

[21] *Id.* P 84.

[22] *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/commodity-insights/en/news-research/latest-news/electric-power/052025-us-gas-fired-turbine-wait-times-as-much-as-seven-years-costs-up-sharply.

resource adequacy concerns. President Trump declared a national energy emergency in Executive Order 14156, "Declaring a National Energy Emergency," in which he determined that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[23] 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."[24] In a subsequent Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[25]

Further, the Department detailed the myriad challenges affecting the Nation's energy systems in its July 2025 "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," issued pursuant to the President's directive in Executive Order 14262. The Department concluded that "[a]bsent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[26]

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," then the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest."[27] 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.

Such is the case here. 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. Given the responsibility of MISO to

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[23] Executive 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.
[24] *Id*.
[25] Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid.
[26] U.S. Department of Energy, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, at 1 (July 2025), https://www.energy.gov/sites/default/files/2025 07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.
[27] 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 Energy. *See* 42 U.S.C. § 7151(b).

identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of Schahfer Units 17 and 18 is necessary to best meet the emergency arising from increased demand, determined shortage, and other causes, and serve the public interest under FPA section 202(c).

To ensure Schahfer Units 17 and 18 will be available if needed to address emergency conditions, Schahfer Units 17 and 18 shall remain in operation until March 23, 2026.

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

A. From December 23, 2025, 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 the Schahfer Units 17 and 18.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by MISO, pursuant to paragraph A. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether Schahfer Units 17 and 18 has operated in compliance with the allowances contained in this Order.

C. All operation 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 condition or to use other geographic or temporal flexibilities available to generators.

D. By January 13, 2026, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of Schahfer Units 17 and 18 consistent with this Order. MISO and NIPSCO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

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

F. 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 11:59 PM Eastern Standard Time (EST) on December 23, 2025, and shall expire at 11:59 PM Eastern Daylight Time (EDT) on March 23, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Denver, Colorado at 6:39 PM EST on this 23rd day of December 2025.

Chris Wright

Chris Wright
Secretary of Energy

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

Indiana Utility Regulatory Commission
Chairman Jim Huston
Commissioner David Veleta
Commissioner David Ziegner

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

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

Exhibit 2
December Culley Order

Department of Energy
Washington, DC 20585

Order No. 202-25-13

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

BACKGROUND

The 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. Unit 2 and Unit 3 began operations in 1966 and 1973, respectively. Unit 2 is slated to cease operations in December 2025.[3]

EMERGENCY SITUATION

Midcontinent Independent System Operator, Inc.'s (MISO) 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.[4] MISO justified this revision by explaining that "Reliability risks associated with Resource Adequacy have shifted from 'Summer only' to a year-round concern."[5] 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.[6]

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

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[1] 16 U.S.C. § 824a(c).
[2] 42 U.S.C. § 7151(b).
[3] As a coal-fired facility, it would be difficult for Culley Unit 2 to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30-60 days to repair if a unit comes offline. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. Further, if Culley were to begin disassembling the plant or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist.
[4] *Midcontinent Independent System Operator, Inc.,* FERC Docket No. ER22-495-000 (Nov. 30, 2021). This request was approved by FERC on August 31, 2022. *See Midcontinent Independent System Operator, Inc.*, 180 FERC ¶ 61,141 (2022).
[5] MISO Transmittal Letter at 3, FERC Docket No. ER22-495-000 (Nov. 30, 2021).
[6] *Id.* at 3-4.

transforming energy landscape."[7] 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 2023/24 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 that the risk of loss of load in the winter and spring seasons, although not as high as in the summer or fall, will nevertheless increase over time.[8]

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.*"[9] 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 highest historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.[10]

These MISO studies indicate that the emergency conditions caused by the loss of generation capacity in MISO extend past the summer season. The evidence indicates that there is also a potential longer term resource adequacy emergency in MISO.

In its 2024 Long-Term Reliability Assessment (LTRA), the North American Electric Reliability Corporation (NERC) notes that the MISO assessment area 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."[11]

When MISO reported the results of its PRA for the 2025-26 Planning Year, it noted that "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources" in the northern and central zones, which include Indiana.[12]

On June 6, 2025, the Organization of MISO States (OMS) and MISO issued the results of their survey, which has been conducted annually for many years to determine the degree to

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[7] MISO, *Attributes Roadmap*, at 3 (Dec. 2023), https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf.
[8] *Id.* at 11.
[9] MISO, *MISO's Response to the Reliability Imperative* (Updated Feb. 2024), https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf.
[10] *Id.* at 12.
[11] *NERC 2024 Long-Term Reliability Assessment*, at 13 (December 2024, corrected July 11, 2025), https://www.nerc.com/globalassets/our-work/assessments/2024-ltra_corrected_july_2025.pdf.
[12] MISO, *Planning Resource Auction: Results for Planning Year 2025-26*, at 13 (April 2025), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf.

which expected capacity resources satisfy planning reserve margin requirements.[13] The 2025 Survey presented projections of resource adequacy for the summer of 2026 and subsequent years. Although the survey projected a potential capacity surplus for the summer of 2026, it also projected that at least 3.1 GW of additional generation capacity beyond currently committed generation capacity must be added to meet the projected planning reserve margin.[14] The 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.[15] Similar results were projected for MISO's winter seasons, with a small surplus of generation capacity in 2026, followed by increasing deficits the following four years.[16]

The primary reasons for these projected deficits also are shown on the OMS-MISO survey. Large quantities 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.[17] 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.[18]

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.[19] 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 away, and are provided an additional three-year grace period to commence commercial operations.[20] 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.[21] Consequently, it is not at all clear that the new ERAS process will result in the addition of new capacity in the next few years.

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[13] OMS and MISO, *OMS-MISO Survey Results* (Updated June 6, 2025), https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf.

[14] *Id.* at 2.

[15] *Id.* at 7.

[16] *Id.* at 9.

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

[18] *Id.*

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

[20] *Id.* P 84.

[21] *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/commodity-insights/en/news-research/latest-news/electric-power/052025-us-gas-fired-turbine-wait-times-as-much-as-seven-years-costs-up-sharply.

More broadly, executive orders issued by President Donald J. Trump on January 20, 2025, and April 8, 2025, underscore the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump likewise declared a national energy emergency in Executive Order 14156, "Declaring a National Energy Emergency," 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."[22] 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."[23] In a subsequent Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[24]

Further, the Department detailed the myriad challenges affecting the Nation's energy systems in its July 2025 "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," issued pursuant to the President's directive in Executive Order 14262. The Department concluded that "[a]bsent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[25]

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," then the Secretary has the authority "to require by order . . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest."[26] 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.

[22] Executive 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.
[23] *Id*.
[24] Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid.
[25] U.S. Department of Energy, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, at 1 (July 2025), https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.
[26] 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 Energy. *See* 42 U.S.C. § 7151(b).

Such is the case here. 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. Given the responsibility of MISO to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of Culley Unit 2 is necessary to best meet the emergency arising from increased demand, determined shortage, and other causes, and serve the public interest under FPA section 202(c).

To ensure Culley Unit 2 will be available if needed to address emergency conditions, Culley Unit 2 shall remain in operation until March 23, 2026.

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

A. From December 23, 2025, 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 dispatched units to the times and within the parameters as determined by MISO, pursuant to paragraph A. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether 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 condition or to use other geographic or temporal flexibilities available to generators.

D. By January 13, 2026, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of Culley Unit 2 consistent with this Order. MISO and CenterPoint Energy shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

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

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

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

H. This Order shall be effective from 11:59 PM Eastern Standard Time (EST) on December 23, 2025, and shall expire at 11:59 PM Eastern Daylight Time (EDT) on March 23, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Denver, Colorado at 6:39 PM EST on this 23rd day of December 2025.

Chris Wright

Chris Wright
Secretary of Energy

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

Indiana Utility Regulatory Commission
Chairman Jim Huston
Commissioner David Veleta
Commissioner David Ziegner

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

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

Exhibit 3
EFG Report

RELIABILITY AND CAPACITY ASSESSMENT OF F.B. CULLEY 2 AND R.M. SCHAHFER 17 AND 18

Carlos Peña and Anna Sommer

January 21, 2026

Table of Contents

Background

The Department of Energy (DOE) has authority under section 202(c) of the Federal Power Act to order "temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy" when it finds that an emergency exists affecting the generation, transmission, or distribution of electricity. Historically, DOE used 202(c) sparingly to respond to short-term emergencies (e.g., hurricanes, major system disturbances), but in 2025 DOE began issuing and repeatedly extending 90-day orders to prevent planned retirements of the Campbell and Eddystone generators.

In CenterPoint Energy Indiana South's (CEIS) service territory, Culley 2, a 90-MW coal unit was planned for retirement on December 31, 2025. In Northern Indiana Public Service Company's (NIPSCO) service territory, R.M. Schahfer Units 17 and 18, two coal units, were scheduled to cease coal-fired operations by December 31, 2025.[1] On December 23, 2025, DOE issued a 202(c) Order forcing all three units to remain operational for an additional 90 days.

Integrated Resource Planning in Indiana

Indiana investor-owned utilities (IOUs) have engaged in integrated resource planning for well over a decade. As vertically integrated utilities who earn a return on equity from capital invested on behalf of their ratepayers, Indiana's IOUs have a significant incentive to construct generators in sufficient quantity to meet their customers' demands. Indiana IRPs look forward across a multi-decade period to determine capacity and energy needs under a variety of demand and other assumptions. These IRPs routinely evaluate retirement of aged generators and construction of new generators against continued operation of the legacy generators. A major objective of integrated resource planning is to make sure that a utility does not have an immediate need for capacity, as DOE contends here. Understanding the supply and demand balance is at the heart of the IRP exercise and directly addresses the concerns raised in DOE's order.

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[1] Wesenberg, R. A. (2024, February). *2024-R.M.-Schahfer-Generating-Station-WDA*. (NIPSCO) Retrieved from https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/ccr/r.m.-schahfer/r.m.-schahfer-generating-station-closure-and-post-closure-care/2024-r.m.-schahfer-generating-station-wda-statement-of-certification.pdf?sfvrsn=612bec51_1

Utility-Level Capacity Position in Early 2026 After Planned Retirements - CenterPoint Energy Indiana South's (CEIS) (F.B. Culley Unit 2)

CEIS's 2025 Integrated Resource Plan (IRP)[2] outlines a planned transition away from coal while maintaining resource adequacy through a diversified portfolio of new generation and demand-side resources. The plan includes the retirement of A.B. Brown Units 1 and 2 by 2023 and F.B. Culley Unit 2, a 90-MW coal unit, by the end of 2025. Rather than relying on large incremental renewable additions in the near term, CenterPoint's Preferred Portfolio emphasizes resources already secured through prior IRPs, including approximately 317 MW of wind from executed power purchase agreements and about 191 MW of Posey Solar, which entered service in 2025. Firm capacity is provided by two new 230-MW natural-gas combustion turbines (A.B. Brown Units 5 and 6), both of which entered commercial operation in 2025. The portfolio is complemented by continued investment in demand-side management (DSM), including approved energy efficiency and demand response programs that provide approximately 11–12 MW of gross annual demand savings, with DSM playing a growing role in meeting planning reserve margin requirements and mitigating future capacity needs.

In the 2025 IRP, CEIS presented a proposed balance of load and resources (Figure 1) indicating that total available capacity continues to exceed summer peak load plus reserve margin, with positive capacity surplus values indicated above the dotted lines. (Note that Figure 1 shows capacity from existing resources as well as those that CEIS intends to acquire or build.) The system relies primarily on natural gas, supplemented by solar, wind, storage, energy efficiency, demand response, and limited capacity purchases.

Importantly, the Reference Case continues to assume that F.B. Culley 2 will be retired while still maintaining adequate reserves in both summer and winter of 2026.

The winter results show a large and persistent capacity surplus above peak demand plus the planning reserve margin across the 20-year planning horizon, reflecting lower winter peak demand relative to summer and the contribution of the modeled resource portfolio, including owned and contracted natural gas–fired generation, wind and solar resources, demand-side programs, and limited market capacity purchases.

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[2] CenterPoint Energy. (2025). *2025 Integrated Resource Plan*. Retrieved from https://www.centerpointenergy.com/en-us/Documents/Midwest/PUBLIC-CEIS-2025-IRP-Volume-1-of-2.pdf

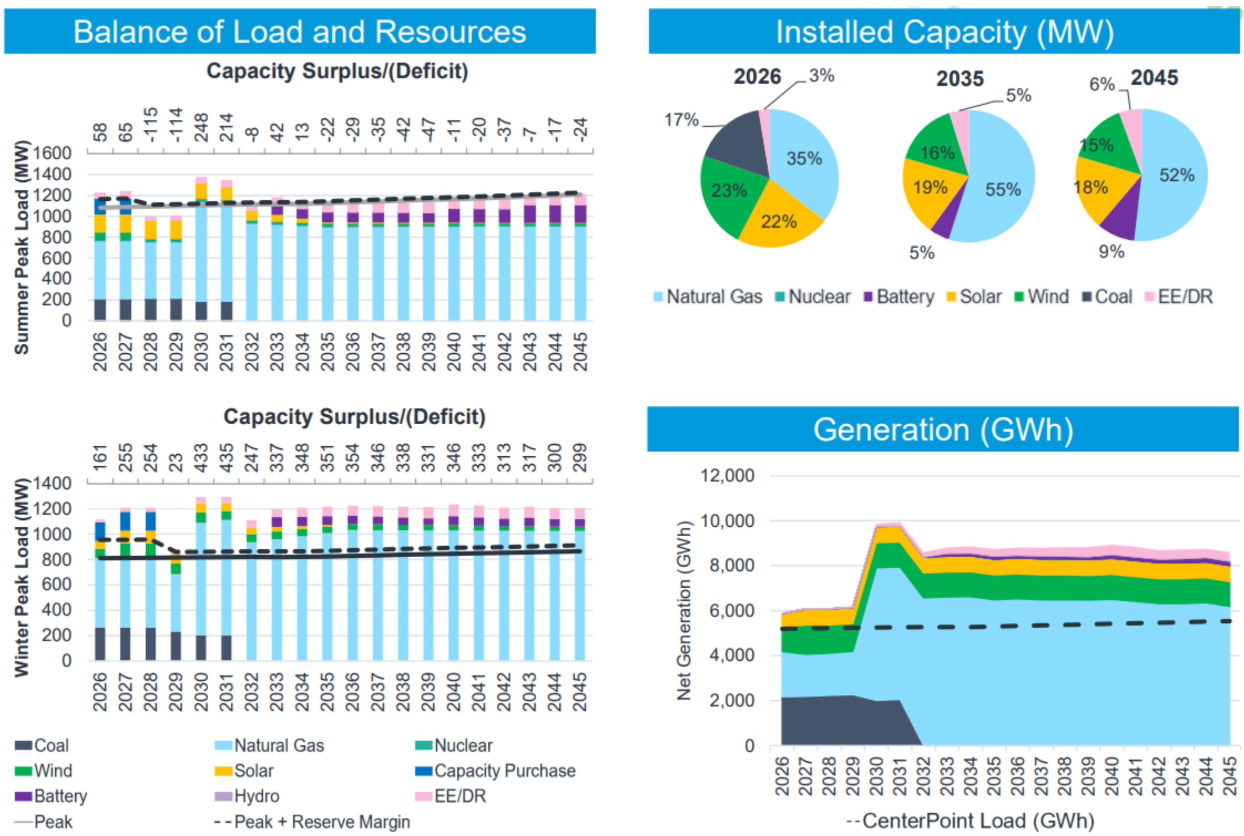

Figure 1. Summer and Winter Reference Case[3]

These results confirm that no seasonal shortfall is expected at any time during 2026. The projected summer capacity gaps in 2028 and beyond will be filled with capacity purchases or construction of a battery. CenterPoint plans to issue an RFP for battery capacity and expects that the battery may be more cost-effective than purchasing capacity.[3]

Utility-Level Capacity Position in Early 2026 After Planned Retirements - NIPSCO (R.M. Schahfer Units 17 and 18)

NIPSCO's 2021 IRP outlined a plan to retire all remaining coal units at the Schahfer station (Units 17 and 18) by 2023 and replace them primarily with wind, solar, battery storage, gas

[3] CenterPoint Energy. (2025). *Public Stakeholder Meeting #4 - October 23, 2025*. Retrieved from https://www.centerpointenergy.com/en-us/Documents/Midwest/IRP.Public.Stakeholder.Meeting.Presentation.11.06.2025.pdf

peakers, and demand-side resources.[4] Subsequent EPA and coal combustion residual filings indicate that the retirement date for Units 17 and 18 was extended to December 2025.[5] NIPSCO's latest planning documents also propose adding a new ~400 MW gas peaker to the Schahfer site and approximately 1,700 MW of renewable resources. [6]

Consistent with this strategy, NIPSCO has obtained IURC approval for multiple renewable projects, including Green River Solar (Cause No. 45818), Dunns Bridge Solar II (Cause No. 45936), Gibson Solar (Cause No. 45500), Fairbanks Solar (Cause No. 46028), Appleseed Solar (Cause No. 45887), and Carpenter Wind (Cause No. 45908).

NIPSCO's 2024 IRP confirms that its near-term plan maintains reliability and meets MISO's evolving resource adequacy rules even as major regulatory changes took effect in 2024. The plan assumes that Schahfer Units 17 and 18 retired 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. As is typical of vertically integrated utilities in the MISO footprint, NIPSCO's IRP contemplates both near- and long-term actions to maintain resource adequacy. It outlines a two-track strategy for new additions: a baseline set of resources that will be acquired regardless of whether large loads materialize, and a contingent set that proceeds only after large-load contracts are signed.[6] In either case, NIPSCO's intent is to ensure compliance with MISO's new direct loss of load (DLOL) capacity accreditation rule, discussed further below.

NIPSCO's 2024 IRP evaluates how its existing and planned accredited capacity compares with the required Planning Reserve Margin (PRM) under two different accreditation frameworks: the current MISO seasonal Resource Adequacy (RA) construct and the forthcoming DLOL accreditation method approved by FERC in October 2024. Figures 2a, 2b, 3a and 3b illustrate this comparison for both summer and winter, showing how NIPSCO's capacity position changes depending on which accreditation regime is applied.

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[4] Northern Indiana Public Service Company (NIPSCO). (2021). *2021 Integrated Resource Plan*. NIPSCO. Retrieved from https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/irp/2021-nipsco-integrated-resource-plan.pdf?sfvrsn=f6ae0251_6

[5] Mark Haney. 2025. TECHNICAL MEMORANDUM - RE: NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC R. M. SCHAHFER GENERATING STATION, WASTE DISPOSAL AREA 40 CFR §257.103(F)(2)(X) PART A DEMONSTRATION ANNUAL PROGRESS REPORT #01-25. Retrieved from https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/ccr/r.m.-schahfer/r.m.-schahfer-generating-station-closure-and-post-closure-care/2025_rm-schahfer-generating-station_wda.pdf?sfvrsn=d4e7f251_3

[6] Northern Indiana Public Service Company (NIPSCO). (2024). *Integrated Resource Plan NIPSCO 2024*. NIPSCO. Retrieved from https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/irp/nipsco_2024-irp.pdf

Figures 2a and 2b indicate that its accredited summer capacity in 2025 and 2026 stays close to or slightly above the required Planning Reserve Margin. In 2025, the figure shows a modest but positive margin, with total accredited resources, gas units, renewables, storage, DSM, and short-term market purchases, providing enough capacity to remain above the PRM even as Schahfer 17 and 18 near retirement. For 2026, NIPSCO's most recent IRP, which assumes Schahfer 17 and 18 retired at the end of 2025, shows that NIPSCO still maintains a comfortable capacity buffer. Overall, the IRP indicates no sign of a summer reliability shortfall in 2026 or even in 2027 and the retirement of Schahfer 17 and 18 does not create a capacity deficiency under the current accreditation rules. Figures 2a and 2b 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. This is a common view of capacity position to understand what needs the utility will address through its IRP process.

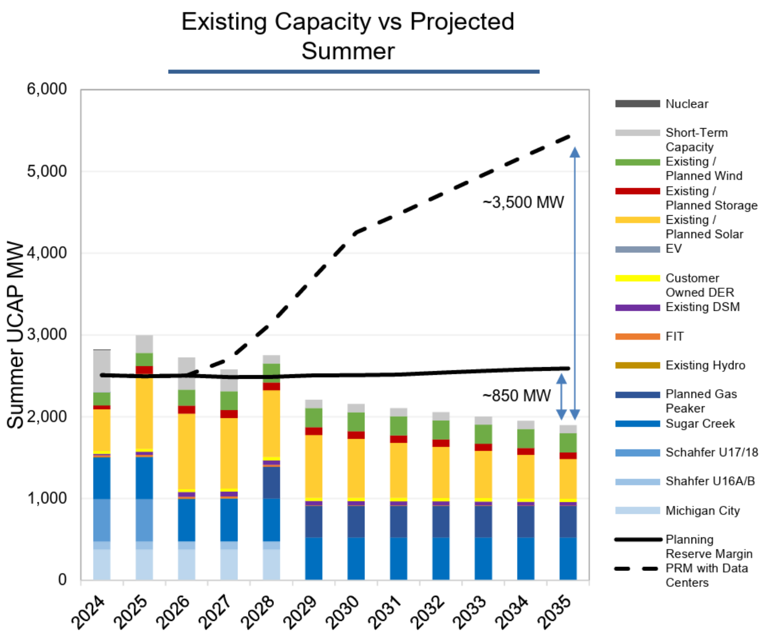

Figure 2a. Summer Resource Adequacy Assessment[6]

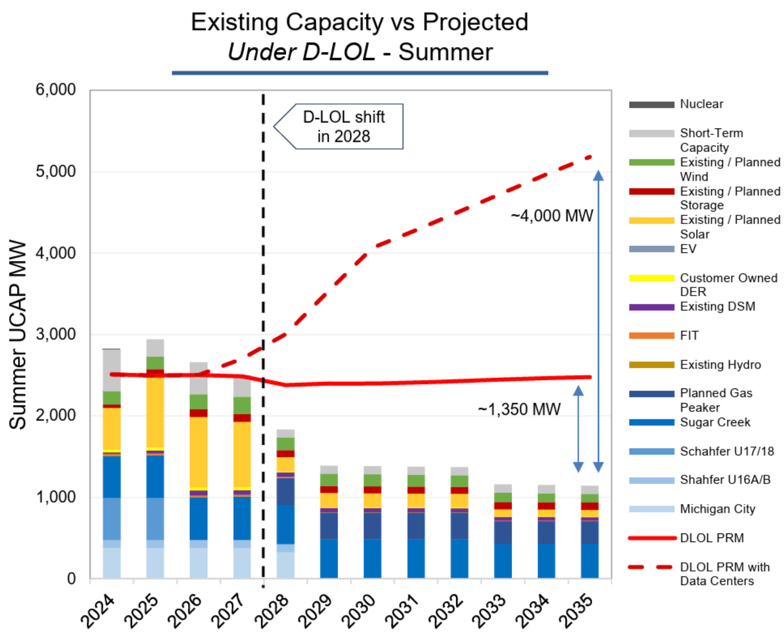

Figure 2b. Summer Resource Adequacy Assessment[6]

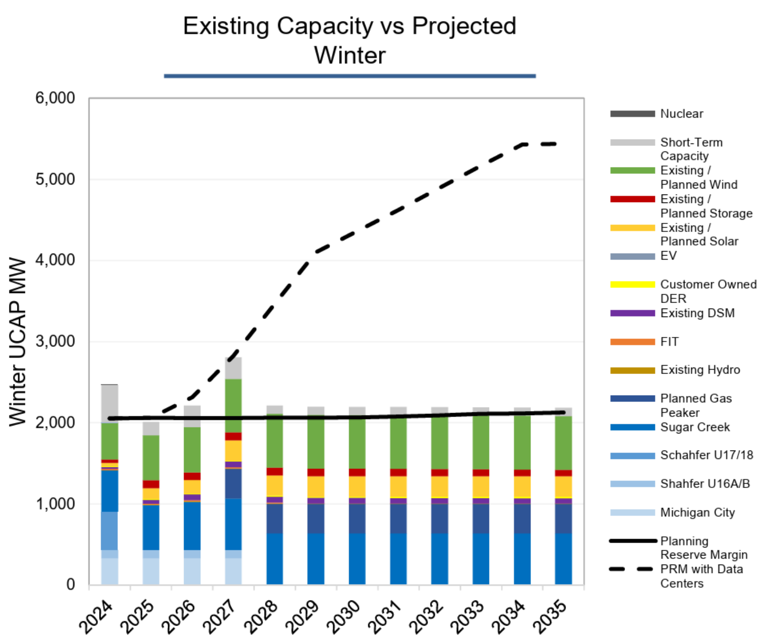

Figure 3a. Winter Resource Adequacy Assessment[6]

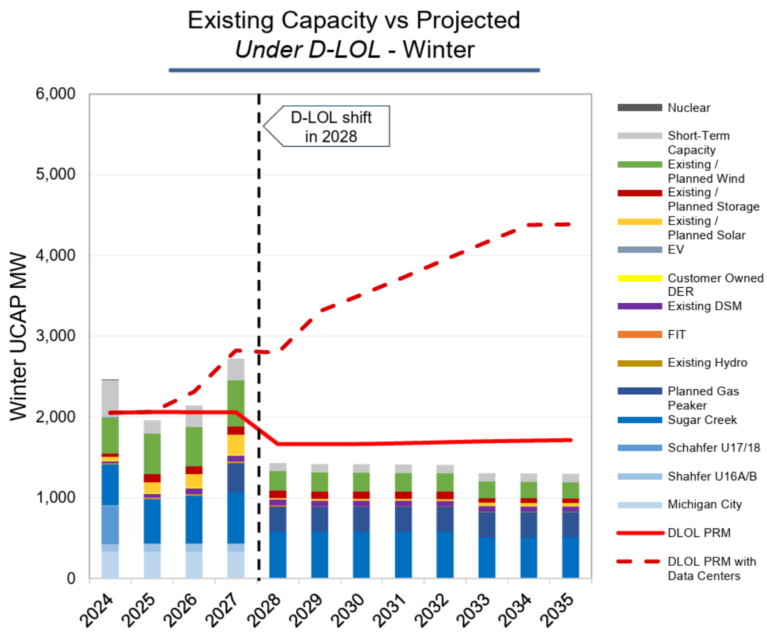

Figure 3b. Winter Resource Adequacy Assessment[6]

The forthcoming DLOL accreditation framework (which MISO will not in fact implement until Summer 2028) shows that the revised PRM requirements for summer 2025 and 2026 remain largely consistent with the results without DLOL. Although the dotted sensitivity lines reflect higher PRM needs under scenarios with significant data-center expansion, these increases occur after 2028 and therefore fall outside the period relevant to the Schahfer retirements.

Figure 3a shows that total accredited winter capacity is slightly above the PRM in 2025 and well above it in 2026. This is driven by higher winter accreditation for wind resources, combined with generally lower winter peak loads. As a result, the IRP demonstrates full winter resource adequacy compliance, with a buffer above the PRM throughout 2025, 2026, and 2027.

Notably, NIPSCO has been planning for the retirement of the Schahfer steam turbines for several years now. The retirement of those turbines will permit the reuse of interconnection rights for additional battery capacity and the Schahfer combustion turbines (CTs) that are currently under construction and will come into service in 2027. Continued operation of the Schahfer steam units once the new capacity is ready to come online will complicate the ability of the CTs and the batteries to inject power because they will be unable to complete the generator replacement interconnection process, which will likely make them ineligible to be counted as capacity resources until they can secure other firm transmission service.

In addition, NIPSCO appears to have ramped down the maintenance of the Schahfer steam units in anticipation of retirement as shown in Figure 4. This is a fairly routine practice since the return on major maintenance for units nearing the end of their life is often negative.

Maintenance expense has fallen from a high of $63 million in 2020 by almost half to $34 million in 2024, the most recent year for which data are available. Continued operation of the Schahfer units for an indefinite period would likely require major investment just to return the units to their normal operating condition.

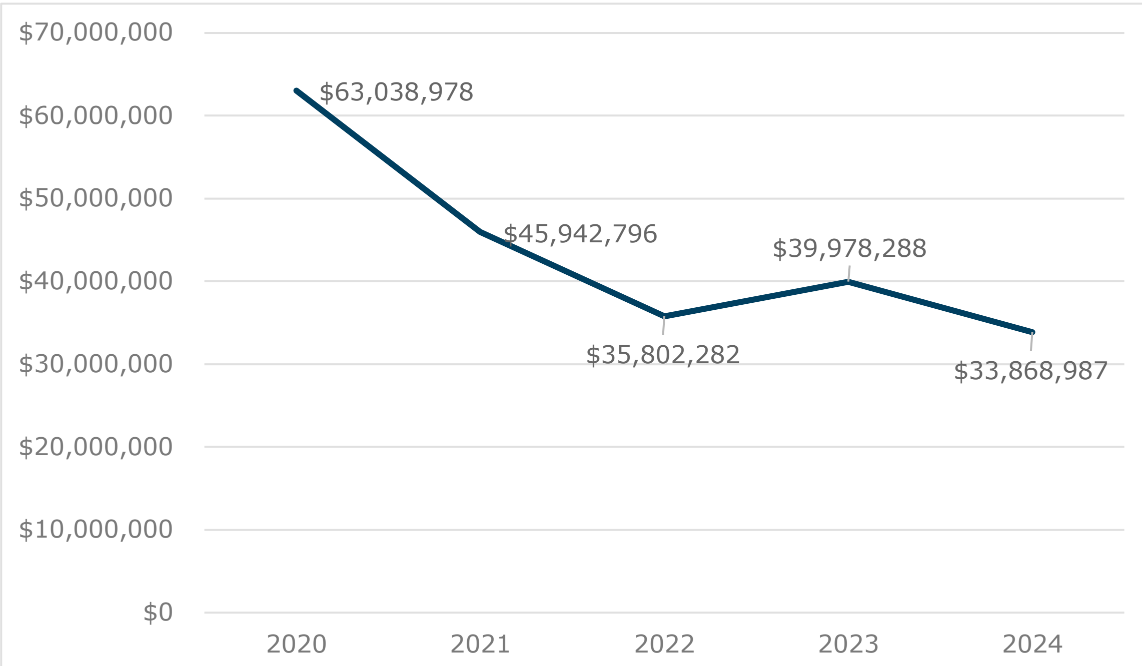

Figure 4. FERC Form 1 Reported Maintenance Expense at Schahfer Steam Units

MISO Resource Adequacy Rules and Shortfall Procedures

MISO's Resource Adequacy framework established in Module E-1 of its Tariff[7] and detailed in BPM-11[8] provides a structure for preventing and managing capacity shortfalls. The foundation of the program is the seasonal Planning Reserve Margin Requirement (PRMR), a total capacity obligation expressed in Zonal Resource Credits (ZRCs), which each Load Serving Entity (LSE) must meet. LSEs can meet this obligation either by providing evidence of capacity associated with resources they own or have contractual rights to via a Fixed

[7] MISO. (2025). *MISO Tariff*. MISO. Retrieved from https://www.misoenergy.org/legal/rules-manuals-and-agreements/tariff/
[8] MISO. (2025). *BPM 011 - Resource Adequacy*. MISO. Retrieved from https://www.misoenergy.org/legal/rules-manuals-and-agreements/business-practice-manuals/

Resource Adequacy Plan (FRAP) or bilateral contract, or by purchasing ZRCs via MISO's Planning Resource Auction (PRA). Target PRMRs are set annually using Loss-of-Load Expectation (LOLE) studies designed to maintain a reliability standard of 0.1 days per year, although the final PRMRs for each region will go up or down depending on the PRA clearing price: MISO requires LSEs to pay for more capacity when it is cheaper, and vice versa. MISO applies this construct across four seasons using Seasonal Accredited Capacity (SAC).

LSEs such as CEIS must demonstrate sufficient accredited capacity to satisfy their PRMR, while also meeting Local Clearing Requirements (LCRs), a separate category of capacity requirements designed to ensure that all cleared capacity is deliverable to each LSE's zone. MISO requires LSEs to either demonstrate they have achieved their PRMR or explicitly opt out of PRMR procurement ahead of the PRA by paying a Capacity Deficiency Charge (CDC). LSEs that opt out of PRMR procurement, or LSEs that are unable to meet their PRMR obligations, are assessed a CDC of 2.748 times the seasonal Cost of New Entry (CONE). CONE represents the cost of procuring a new generator that would be able to provide the short capacity. Under the Reliability-Based Demand Curve, a materially short zone in the PRA clears at or near CONE. Together, these mechanisms create strong financial incentives for LSEs to secure adequate capacity well in advance of the PRA and the operating period.[0]

When a resource committed for RA cannot perform due to retirement, suspension, catastrophic outage, ICAP deferral failure, or a planned outage exceeding 31 days, the Market Participant must procure replacement ZRCs. Failure to do so results in a Capacity Replacement Non-Compliance Charge (CRNCC), calculated using the Seasonal Auction Clearing Price plus the Daily Zonal CONE. MISO further enforces real-time performance through penalties on Load Modifying Resources (LMRs), including Demand Response and Behind-the-Meter Generation, when they fail to respond during declared emergencies.[7]

MISO relies on a structured escalation process to deploy resources including committed capacity resources. Operators issue Maximum Generation advisories and alerts, commit emergency resources, deploy LMRs through the Demand Side Resource Interface, and curtail non-firm exports before affecting firm load. If forecast demand and operating reserve requirements cannot be met through normal commitments, MISO first exhausts a defined set of pre-Energy Emergency Alert (EEA) actions, including committing all available generation and storage up to emergency limits, deploying emergency-only demand response, scheduling qualified external resources and emergency imports from neighboring systems, and initiating emergency energy purchases. If these actions are insufficient, MISO declares EEA-1 or EEA-2 and continues mitigation through emergency demand response dispatch, public appeals for load reduction, voltage reductions, and additional curtailment of load-modifying resources. Only after these measures fail to restore energy balance does MISO escalate to EEA-3, at which point firm load shedding becomes imminent or necessary. Scarcity pricing at the Value of Lost Load (VOLL) is applied when emergency imports, emergency unit commitments, and all available reserves are insufficient to rebalance the system.[7]

MISO Zone 6 Capacity Position for Planning Year 2025/26

MISO's 2025 PRA for Planning Year (PY) 2025/26[9] provides a quantitative snapshot of Zone 6's resource adequacy position during the period when F.B. Culley 2 and Schahfer 17 and 18 were scheduled to retire. The Planning Resource Auction results for winter 2025–26 and spring 2026 in Table 1 indicate the following:

	Winter 2025-2026	Spring 2026
Zone 6 Final PRMR	18,685.7 MW	18,166.7 MW
Offer Submitted (Including FRAP)	14,679.5 MW	15,824.7 MW
Committed Capacity (offers cleared + FRAP) in Zone 6	14,331.5 MW	15,181.0 MW
Zone 6 LCR	11,074.8 MW	10,377.1 MW
Net Imports into Zone 6	4,354.1 MW	2,985.6 MW

Table 1. Planning Resource Auction Results for Winter 2025–26 and Spring 2026 Abbreviations: Planning Reserve Margin Requirement (PRMR), Fixed Resource Adequacy Plan (FRAP), Local Clearing Requirement (LCR)

For both seasons, Zone 6 maintains a substantial surplus of local committed capacity relative to its LCR, indicating that only a portion of the committed resources are needed to satisfy local adequacy obligations. Even before considering imports, committed capacity exceeds the LCR by approximately 3,257 MW (about 29%) in Winter 2025–26 and by 4,804 MW (about 46%) in Spring 2026, underscoring a comfortable local capacity position in both seasons.

In other words, these figures indicate that local deliverability is not at risk. Even following the Culley 2 and Schahfer 17 and 18 retirement, Zone 6 retains several gigawatts of surplus local capacity beyond what is required to meet the 2026 LCR.

Zone 6 does rely on imports; however, imports remain well below applicable limits in both seasons (see Table 2). Zonal Import Ability (ZIA) reflects the physical transmission capability to import power into the zone, while the Capacity Import Limit (CIL) represents the planning

[9] MISO. 2025. Planning Resource Auction Results for Planning Year 2025-26. Retrieved from https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf

constraint applied in the PRA to ensure reliable deliverability. Actual imports are well within both limits, indicating that Zone 6 is not import-constrained and does not rely excessively on imported capacity for resource adequacy.

	Winter 2025-2026	Spring 2026
Imports	4,354.1 MW	2,985.6 MW
ZIA	7,690 MW	9,176 MW
CIL	7,927 MW	9,457 MW
	Imports use about 23% of Final PRMR, but only ≈55% of CIL and ≈57% of ZIA.	Imports are about 16% of PRMR, and only ≈32% of CIL/ZIA.

Table 2. Zone 6 Imports Fall Below Import Limits

These figures demonstrate that, even after accounting for imports needed to meet PRMR, Zone 6 still has several gigawatts of unused import headroom (roughly 3.3 GW in winter and 6+ GW in spring). Neither these results nor the ones discussed above indicate a reliability emergency that constitute a need to keep F.B. Culley 2 and Schahfer 17 and 18 online.

Taken together, the PRA results for Winter 2025–26 and Spring 2026 indicate that Zone 6 meets its PRMR in both seasons without any RA shortfall. Local deliverability remains strong, with an estimated 3–5 GW of capacity above the LCR, and the imports required to satisfy PRMR are well within transfer limits, leaving substantial headroom. Collectively, these indicators support the conclusion that the planned retirements of F.B. Culley 2 and Schahfer 17 and 18 at the end of 2025 would not have created a resource adequacy concern for 2026.

In both Winter 2025/26 and Spring 2026, the MISO system exactly meets its Final PRMR of roughly 131 GW, with slightly more capacity offered than required and only modest reliance on transfers. In winter, approximately 1.7 GW of imports from external resource zones, together with about 0.6 GW of net exports from the South to the North. In spring, a similar pattern emerges, with about 1.5 GW of imports and 1.3 GW of South-to-North exports, all well within transfer capability. The uniform, relatively low Auction Clearing Price (ACPs) of $33.20/MW-day in winter and $69.88/MW-day in spring indicate that, even after accounting for these transfers, the system remains adequately supplied and does not face capacity shortfall risk in 2026.

Conclusion

MISO's planning resource auction and the Integrated Resource Plans of both NIPSCO and CEIS support a conclusion that the retirements of F.B. Culley 2 and Schahfer 17 and 18 at the end of 2025 would not give rise to a resource adequacy emergency during the first 90 days of 2026. Should circumstances change, MISO has emergency protocols in place to address unplanned events such as loss of a generator or transmission line that do not rely on extending operation of these generators.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

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

Exhibit 4
Powers January Declaration

SCHAHFER 17 & 18 AND CULLEY 2 DECLARATION OF BILL POWERS, P.E.

January 2026

I, Bill Powers, P.E., declare as follows:

1. I am the principal of Powers Engineering, an engineering firm that consults on issues related to the operation of, and control of pollution from, power plants, including coal-fired power plants. My office is located in San Diego, California. My professional and educational experience is summarized in the curriculum vitae attached to this declaration (Attachment A).

2. I received a Bachelor of Science degree from Duke University in Mechanical Engineering and a Master of Public Health degree in Environmental Sciences from the University of North Carolina. I am a registered engineer in the state of California.

3. I have been an independent engineering consultant with a focus on power systems since 1994. In prior employment, I received "Engineer of the Year" awards from ENSR Consulting and Engineering in 1991 (before ENSR merged with AECOM) and from the Naval Energy and Environmental Support Activity ("NEESA") office within the U.S. Navy in 1986 (before NEESA was subsumed by the Naval Facilities Engineering Service Center). I also received a "Productivity Award of Excellence" from the U.S. Department of Defense in 1985. I worked extensively on Navy and Marine Corps coal-fired power plant shore installations in the 1980s as a Navy civilian engineer.

4. I have over 40 years of experience in the fields of power plant operations and environmental engineering. My technical specialties include, among others: combustion

equipment permitting, testing, and monitoring; air emission control assessments; air pollution control equipment retrofit design/performance; and power plant cooling system conversion.

5. I have served as an engineering expert for a wide array of clients, including private companies, non-profits, and government entities, including the cities of Carlsbad, California and Houston and Dallas, Texas. In this role, I have provided expert testimony, conducted feasibility studies, and consulted on power plant engineering issues in a number of states, including Arkansas, California, Connecticut, Florida, Georgia, Kentucky, Maryland, Missouri, Nevada, North Carolina, New York, and Tennessee.

6. I have extensive experience with coal-fired power plants. In 2022, I provided expert testimony before the North Carolina Public Utility Commission regarding Duke Energy's proposed plan to maintain coal-fired units in its electric supply portfolio—a proposal the company advanced in part based on its belief that those units were necessary to meet winter peak demand. Throughout my career, I have consulted on the control of pollution from coal-fired power plants. Examples include serving as the lead engineer on a system and performance audit of continuous emissions monitoring systems at a coal-fired power plant in Nevada, and on a project to assess and address the root causes of opacity exceedances at Ameren Missouri's Labadie, Meramec, and Rush Island coal-fired power plants. I have also frequently provided expert testimony on coal-fired power plants. For example, I testified on air pollution controls at a coal-fired power plant in Massachusetts, and on the correlation between a Georgia coal-fired power plant's particulate matter emissions and opacity excursions, among other issues. I also served as a testifying expert on an evaluation of the air emissions limits and control technologies for a proposed coal-fired power plant in Arkansas. Finally, I have submitted or will submit expert declarations to the Department of Energy in the J.H. Campbell Generating Complex Section

202(c) matters (Michigan) in June 2025 and September 2025 and the Craig Station Section 202(c) matter (Colorado) in January 2026. In those declarations, I have documented the dramatic reduction in ongoing capital and major maintenance investments by the plant owners in the years prior to the planned permanent retirement date, and the impact of that lack of investment on the reliability of the unit(s).

7. I am also very familiar with "peaking" units, which are intended to ramp up and provide electricity during times of peak demand, such as during hot summer months. For example, in 2001, I prepared all aspects of the air permit applications for five 50 MW simple-cycle gas turbine installations in response to an emergency request by the California state government for additional peaking power.

8. I am familiar with the U.S. Department of Energy's ("DOE") December 23, 2025 order regarding R.M. Schahfer Units 17 and 18 (Order No. 202-25-12) ("Schahfer Order").

9. The R.M. Schahfer power plant ("Schahfer") consists of two coal-fired generating units, Unit 17 and Unit 18, each with a generating capacity of 361 MW, and two gas-fired combustion turbines, 78 MW Unit 16A and 77 MW Unit 16B.[1]

10. Northern Indiana Public Service Company LLC ("NIPSCO") is the owner and operator of R.M. Schahfer Generating Station. NIPSCO has submitted key filings concerning the operations of Schahfer Unit 17 and Unit 18 to state and federal regulatory bodies. As a result, I rely primarily on NIPSCO filings in this declaration.

11. The in-service dates for Schahfer Units 17 and 18 are 1983 and 1986, respectively.[2]

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[1] NIPSCO 2024 Integrated Resource Plan ("IRP"), p. 102.

[2] NIPSCO 2024 IRP, p. 104.

12. The NIPSCO plan for Schahfer Units 17 and 18 was to retire the units by December 31, 2025.[3]

13. I am familiar with the U.S. Department of Energy's ("DOE") December 23, 2025 order regarding Culley Unit 2 (Order No. 202-25-13) ("Culley Order").

14. The F.B. Culley Generating Station ("Culley") consists of two coal-fired generating units, 90 MW Unit 2 and 270 MW Unit 3.[4]

15. CenterPoint Energy Indiana South ("CEIS") is the owner and operator of F.B. Culley Generating Station. CEIS has submitted key filings concerning the operation of Culley Unit 2 to state and federal regulatory bodies. As a result, I rely primarily on CEIS filings in this declaration.

16. The in-service date for Culley 2 was 1966.[5]

17. The initial CEIS plan was to permanently retire Culley 2 by the end of 2023. The planned retirement date was subsequently extended to December 31, 2025.[6]

18. I was asked by Earthjustice (legal counsel for certain Public Interest Organizations) to develop an opinion on: (A) the extent to which Schahfer 17 and 18 and Culley 2 can operate reliably after December 31, 2025; (B) whether Schahfer 17 and 18 and Culley 2 can operate effectively as peaking units; (C) the cost to rehabilitate Schahfer 17 and 18 to operate reliably for extended periods of time, (D) the environmental impact of continued operation of Schahfer 17 and 18 and Culley 2; and (E) easily attainable steps DOE can require to ensure

[3] "NIPSCO 2024 IRP, p. 1. "As previously planned, NIPSCO will complete the retirement and shutdown of Schahfer Units 17 and 18 by the end of 2025 and continue activities associated with the implementation of transmission system reliability upgrades."

[4] CEIS 2025 IRP, p. 12.

[5] Ibid.

[6] CEIS 2020 IRP, p. 254; CEIS 2023 IRP, pp. 235, 279, 280.

Schahfer 17 and 18 and Culley 2 operate in a manner consistent with environmental requirements and that minimizes adverse environmental impacts.

19. While there may be alternatives to the continued operation of Schahfer 17 and 18 and Culley 2 that are available to DOE to address the circumstances DOE describes in the Schahfer Order, my analysis notes but does not focus on these alternatives. As such, my analysis of alternatives should not be understood to be a comprehensive survey of alternatives. I also do not opine on the claimed energy emergency described in the Schahfer Order.

Section 1. The extent to which Schahfer 17 and 18 and Culley 2 can operate reliably beyond December 2025

A. Schahfer 17 and 18:

20. In my professional opinion, it is unlikely that Schahfer 17 and 18 can be depended upon to operate reliably beyond December 2025 as an emergency generation resource. Even before the scheduled retirement date of December 31, 2025, Schahfer 17 and 18 suffered from poor reliability. Nationally, the average coal unit forced outage rate in 2023 was 12.0 percent.[7] In contrast, Schahfer 17 and 18 had forced outage rates in 2024 of 18.8 percent and 13.2 percent, respectively[8]—well above the average coal unit forced outage rate. The forced outage rates in the first nine months of 2025 were similarly high for Schahfer 17 at 15.9 percent and spectacularly high for Schahfer 18 at 78.2 percent.[9] The current condition of Schahfer 18 is so bad that it must be rebuilt, according to the president of NIPSCO.[10] He also indicated in early

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[7] NERC, *2024 State of Reliability*, p. 59 (June 2024).

[8] Indiana Utility Regulatory Commission ("IURC") Cause Nos. 38706 FAC 143 – 149, Direct Testimony of David Saffran on behalf of NIPSCO (Q1-Q4, 2024 and Q1-Q3, 2025), Att. 4-A, at 1.

[9] Ibid.

[10] NIPSCO president, statement at public event of the Indiana Utility Regulatory Commission in early December 2025, prior to the issuance of the US DOE Schahfer Order: "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), and it continues, we'll likely have to do some work on 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

December 2025 that it would take six months or more to have it running again and capable of running for an extended period of time (assuming the necessary investments are made). The NISPCO president indicated work would be needed on Schahfer 17 as well.[11]

21. The nature of the Schahfer 17 and 18 forced outages in 2024 and 2025 reflects the impact of worn and difficult-to-repair or replace coal unit components on operational reliability. Outages tended to be long and recurrent. Tables 1 and 2 document the longest Schahfer 17 and 18 outages by description and duration in 2024 and 2025 (first three quarters), respectively.

Table 1. Longest 2024 Outages, Schahfer 17 and 18 - Description and Duration[12]

Unit	Outage description	Total duration (hours)
17	• boiler tube leaks (2 outages)	1,645
18	• ESP problems (1 outage) • boiler tube leaks (3 outages) • pulverizer mill trip, extensive damage	147 159 614

Table 2. Longest 2025 Outages, Schahfer 17 and 18 - Description and Duration[13]

Unit	Outage description	Total duration (hours)
17	• boiler tube leaks (5 outages)	1,044
18	• boiler tube leak (1 outage) • steam turbine bearing vibration/failure • high turbine bearing vibration	150 2,980 1,996

22. NIPSCO determined in its 2018 IRP to retire the Schahfer (coal) Units 14, 15, 17, and 18 by the end of 2023. NIPSCO in fact retired the larger Units 14 and 15 in 2021, and

rebuilt. […] We're taking some steps to be able to do that, but it will take time; it can take 6 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." IURC 2025 Winter Reliability Forum (December 2, 2025), https://www.youtube.com/watch?v=bCzALF4V45M, beginning at 51:35.

[11] Ibid.

[12] Direct Testimony of David Saffran on behalf of NIPSCO, IURC Cause No. 38706 FAC 143, FAC 145, FAC 146.

[13] Direct Testimony of David Saffran on behalf of NIPSCO, IURC Cause Nos. 38706 FAC 147, FAC 148, FAC 149.

confirmed its retirement plan for Schahfer 17 and 18 in its 2021 IRP. Subsequently, in 2022, NIPSCO resolved to retire Schahfer 17 and 18 in 2025, a plan it reaffirmed in its 2024 IRP.[14]

23. The high forced outage rates point to degraded Schahfer 17 and 18 reliability. Expected reliability 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.

24. Schahfer 17 has been operating for 43 years, Schahfer 18 for 40 years.[15] A typical coal unit has an economic design life of 30 to 40 years and a typical operational lifetime of 40 to 50 years.[16,17] As a power plant ages, the equipment degrades even though it is maintained and inspected, and it is unable to perform as well as brand-new equipment. It becomes necessary to upgrade or replace degraded equipment to a new condition.[18]

25. In the case of Schahfer 17 and 18, NIPSCO's stated objective was to keep the units operating until December 31, 2025 and shut them down at that time. The objective was *not* to maintain a high level of reliability beyond December 31, 2025. A high level of reliability would be necessary for Schahfer 17 and 18 to ramp up and work reliably under emergency demand conditions.

24. In particular, Schahfer 18's sharp increase in year-over-year forced outage rate from 2024 to 2025 is alarming, from 13.2 percent to 78.2 percent, especially if Schahfer 18 is expected to continue to operate past the scheduled December 31, 2025 retirement date. The

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[14] NIPSCO 2024 IRP, p. 1.

[15] Ibid, p. 104.

[16] M. Hafner, G. Luciani, *The Palgrave Handbook of International Energy Economics*, p. 127 (2022).

[17] International Energy Agency, *The role of CCUS in low-carbon power systems*, p. 18 (2020).

[18] Intertek, *Update of Reliability and Cost Impacts of Flexible Generation on Fossil-fueled Generators*, prepared for Western Electricity Coordinating Council, May 12, 2020, p. 7: https://www.wecc.org/system/files/documents/anchor_data_set/2024/1r10726%20WECC%20Update%20of%20Reliability%20and%20Cost%20Impacts%20of%20Flexible%20Generation%20on%20Fossil.pdf.

increased forced outage rate was likely exacerbated by underspending on operations and maintenance (O&M) costs. Winding down O&M costs and failing to invest in long-term maintenance needs is common practice for end-of-life plants and is considered financially prudent. Plants such as R.M. Schahfer that have likely underspent on coal unit capital and/or O&M are at greater risk of future forced outages.[19]

27. In my professional opinion, it is unlikely that Schahfer 17 and 18 can reliably dispatch. As described above, NIPSCO has likely deferred capital and major maintenance spending, which is reflected in the plant's forced outage rate.

B. Culley 2:

28. It is unlikely that Culley 2 can be depended upon to operate reliably beyond December 2025 as an emergency generation resource. Even before the scheduled retirement date of December 31, 2025, Culley 2 was experiencing deteriorating reliability. As stated above, the national average coal unit forced outage rate in 2023 was 12 percent.[20] In contrast, Culley 2 had a forced outage rate of 32.4 percent in 2024 following years of steadily rising forced outage rates, as shown in Table 3.

Table 3. Culley 2 Forced Outage Rate,[21] 2020-2024

Unit	2020	2021	2022	2023	2024
Culley 2	6.3%	21.9%	26.6%	24.8%	32.4%

29. CEIS states that Culley 2 "has run past its useful life" as the basis for its planned retirement at the end of 2025.[22] This fact, and the rising forced outage rates, point to degraded

[19] Intertek, p. 7.
[20] NERC, *2024 State of Reliability*, p. 59 (June 2024).
[21] CenterPoint Energy, 2024 CEIS Electric Performance Report, p. 24.
[22] CEIS 2025 IRP, p. 30.

Culley 2 reliability. Expected reliability will degrade further if the unit is required to run for extended periods of time, is required to stop and start numerous times, or attempts to start up at an accelerated rate in response to extreme demand conditions.

30. Culley 2 has been operating for 60 years.[23] As stated above, a typical coal unit has an economic design life of 30 to 40 years and a typical operational lifetime of 40 to 50 years.[24,25] Also as stated above, a power plant's equipment will degrade in quality and performance over time, and upgrades and replacement will be necessary to maintain reliability.

31. The steady increase in the Culley 2 year-over-year forced outage rate is concerning, especially if Culley 2 will operate past the December 31, 2025 retirement date. The increased forced outage rate was likely exacerbated by underspending on O&M costs. CEIS's public filings show that its Culley 2 maintenance expenditure declined about 20% from 2022 to 2023 in account 512 (Maintenance of Boiler Plant).[26] 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.[27]

32. In my professional opinion, it is unlikely that Culley 2 can reliably dispatch.

Section 2. Whether Schahfer 17 and 18 and Culley 2 can operate effectively as a peaking units

A. Schahfer 17 and 18:

[23] Ibid, p. 12.

[24] M. Hafner, G. Luciani, *The Palgrave Handbook of International Energy Economics*, p. 127 (2022).

[25] International Energy Agency, *The role of CCUS in low-carbon power systems*, p. 18 (2020).

[26] CenterPoint Indiana response to data request OUCC 26.4 in IURC Cause No. 45990. Note that the 2023 expenditures are through September only. 2023 expenditures have been extrapolated to a full year to enable a direct comparison to 2022 expenditures.

[27] Intertek, p. 7.

33. In my opinion, Schahfer 17 and 18 cannot operate effectively as peaking units that would be dispatched with only a few hours of notice to meet an extreme demand condition.

34. Coal units generally, including Schahfer 17 and 18, cannot serve as peaking units that respond to extreme peak demand on short notice. Coal units are designed for baseload, around-the-clock operation.[28] Schahfer 17 and 18, started "cold" (room temperature), take a minimum of 23 hours to reach full load operation.[29] The ramp rate is slow to avoid excessive thermal stress on components exposed to heat. In contrast, utility-scale battery storage can dispatch from a cold start to full power in a matter of seconds.[30] Similarly, combustion gas turbines, designed for fast-response peaking duty, can go from a cold start to full power in 5 to 10 minutes.[31]

35. Coal units cannot respond to extreme demand events unless they are fully online several hours before the high demand situation occurs. In other words, coal units need substantial lead time to be fully operational at or before an extreme peak demand is reached. They cannot be dispatched from an offline "cold" status to address extreme emergency demand if an emergency is declared only a few hours before the demand must be met.

36. Grid demand increases rapidly on peak demand days. NIPSCO is a member of the Midcontinent Independent System Operator ("MISO"),[32] a regional transmission grid operator. MISO may have only a few hours' notice that an extreme peak demand day is

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[28] CenterPoint Energy, 2025 IRP, p. 19. "MISO recognizes the major changes in the way energy is being produced. Traditionally, baseload coal plants produced energy at a constant level around the clock, while peaking gas plants were available to come online as needed to meet peak demand."

[29] NIPSCO response to data request CAC 1-013(c) from a CPCN case in 2024, IURC Cause No. 45947.

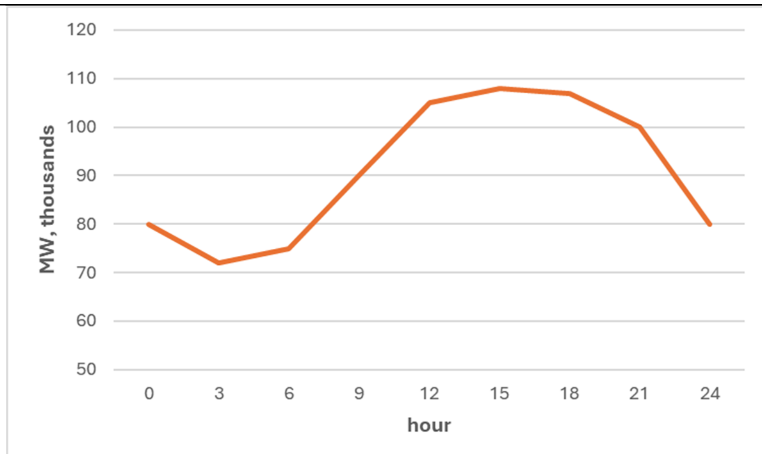
[30] NERC, *Energy Storage: Overview of Electrochemical Storage*, p. 1 (Feb. 2021). https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Master_ESAT_Report.pdf ("BESS are a well suited technology to provide short-term grid contingency support (tens of seconds) . . . .").

[31] General Electric, *Get to know the LM6000* (webpage) (2025), https://www.gevernova.com/gas-power/products/gas-turbines/lm6000. ("With around five minutes to ramp up from start-up to full power . . . .").

[32] NIPSCO 2024 IRP, p. ES-3.

developing. The need to bring on additional generation resources to meet an extreme peak may be uncertain until the hours immediately prior to the actual peak. An example of this can be seen in Figure 1, which shows a modeled 24-hour demand curve for MISO on a representative high-demand summer day. Given their lengthy startup period, Schahfer 17 and 18 would not be able to meet a previously unanticipated exceptional peak demand, unless they were already online.

Figure 1. MISO 24-hour summer peak day demand curve[33] (MW)



37. Bringing Schahfer 17 and 18 from a cold start condition to full output to meet extreme demand would also be expensive. According to the National Association of Regulatory Utility Commissioners ("NARUC"), the estimated cost to "cold start" a coal-fired power plant is \$417 per MW of capacity.[34] The net capacity of Schahfer 17 and 18 is 722 MW. Therefore, the estimated cost to start up Schahfer 17 and 18 from a cold start condition would be approximately \$300,000. (722 MW × \$417 per MW = \$301,074).

38. Alternatively, instead of starting cold, NIPSCO could elect to run Schahfer 17 and 18 on a "Must Run" or "Self-Scheduled" basis, solely to be prepared for a potential near-term

[33] MISO, *Attributes Roadmap*, December 2023, p. 26 ("Base Case").

[34] NARUC, *Recent Changes to U.S. Coal Plant Operations and Current Compensation Practices* (Jan. 2020), https://www.osti.gov/servlets/purl/1869928, p. 16.

high-peak demand. That approach would be even more expensive and, as discussed below, highly polluting.

B. Culley 2:

39. Culley 2 cannot serve as peaking unit that respond to extreme peak demand on short notice. As stated above, coal units are designed for baseload, around-the-clock operation. As noted for Schahfer 17 and 18, coal units started cold may require 23 hours or more to reach full load operation.

40. CEIS is also a member of the MISO. As shown in Figure 1, MISO may have only a few hours' notice that an extreme peak demand day is developing. As with Schahfer, the need to bring on additional generation may be uncertain until the hours immediately prior to the actual peak. Culley 2 would not be able to meet a previously unanticipated exceptional MISO peak demand unless it was already online.

41. Bringing Culley 2 from a cold start condition to full output to meet extreme demand would also be expensive. Again, according to the NARUC, the estimated cost to "cold start" a coal-fired power plant is $417 per MW of capacity.[35] The net capacity of Culley 2 is 90 MW. Therefore, the estimated cost to start up Culley 2 from a cold start condition would be approximately $37,500. (90 MW × $417 per MW = $37,530). As with Schahfer 17 and 18, if Culley 2 were run on a "Must Run" or "Self-Scheduled" basis solely to be prepared for a potential demand peak, costs would be even higher.

Section 3. The cost to rehabilitate Schahfer 17 and 18 to operate reliably for extended periods of time

[35] Ibid, p. 16.

42. NIPSCO has projected the investment necessary to operate Schahfer 17 and 18 through 2027.[36] In IURC Cause No. 46120, NIPSCO's response to OUCC Data Request 9-004 Confidential Attachment C, NIPSCO calculates that operating Schahfer Units 17 and 18 beyond 2025 would require more than $1 billion of additional investment through 2027.

43. Utilities typically phase out capital and major maintenance spending on coal units scheduled for retirement a few years before the planned retirement date.[37] This makes fiduciary sense, as there would be little operating lifetime over which to recover the investment. However, as a result these units are less reliable in the period immediately prior to retirement.

Section 4. Environmental impact of continued operation of Schahfer 17 and 18

A. Schahfer 17 and 18:

46. Burning coal emits air pollutants and greenhouse gases. These pollutants include nitrogen oxides ("NO_x"), sulfur dioxide ("SO_2"), carbon dioxide ("CO_2"), and particulate matter ("PM") among others. NO_x is a lung irritant and a precursor to ozone formation.[38] SO_2 can harm the respiratory system and contribute to the formation of acid rain.[39] PM emissions can cause decreased lung function and increased respiratory symptoms.[40] In addition, NO_x, SO_2, and PM_{10}

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[36] NIPSCO response to data request OUCC 9-004 from a general rate case in 2024-2025, IURC Cause No. 46120. "Pulled from the 2024 analysis, OUCC Request 9-004 Confidential Attachment C shows NIPSCO's calculation of what it considers a reasonable estimate, based on presently available information, of the total investment cost necessary to operate Schahfer Units 17 and 18 through 2027."

[37] See W. Powers June 2025 Declaration in J.H. Campbell Section 202(c) matter (DOE Order No. 202-25-3).

[38] U.S. EPA, *Basic Information about NO_2*, webpage accessed August 31, 2025: https://www.epa.gov/no2-pollution/basic-information-about-no2.

[39] U.S. EPA, *Sulfur Dioxide Basics*, webpage accessed August 31, 2025: https://www.epa.gov/so2-pollution/sulfur-dioxide-basics.

[40] U.S. EPA, *Health and Environmental Effects of Particulate Matter (PM)*: https://www.epa.gov/pm-pollution/health-and-environmental-effects-particulate-matter-pm.

contribute to the formation of atmospheric haze, which reduces visibility.[41] Through its regional haze visibility modeling, Indiana found that air pollution from R,M, Schahfer is a contributor to visibility impairment.[42] CO_2 emissions are the primary cause of global warming.[43]

47. Large quantities of these pollutants and greenhouse gases will enter the atmosphere if uncontrolled. R.M. Schahfer Generating Station's Title V air permit sets out the emission limits and other requirements the facility must comply with to reduce air pollution from coal combustion and related operations.[44]

48. Coal-burning power plants must include air emission control equipment to reduce the pollutants in the coal boiler exhaust gas stream. The equipment still allows some level of pollution to be emitted, but it reduces the amount of pollutants entering the atmosphere.

49. The air cleaning equipment at Schahfer 17 and 18 includes electrostatic precipitators (ESPs), wet limestone scrubbers, and low-NO_x burners with over-fire air.[45] ESPs remove PM from the boiler exhaust gas. Wet limestone scrubbers (also known as flue gas desulfurization) remove SO_2. The low-NO_x burner system is intended to limit the amount of NO_x generated at the point of combustion in the boiler.

50. Tables 2a and 2b summarize the projected SO_2, NO_x, CO_2, and PM emissions from Schahfer 17 and 18 for the 90-day period from January 1, 2026 to March 31, 2026, assuming the same level of Schahfer 17 and 18 electricity generation as recorded in January,

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[41] Colorado APCD, *Best Available Retrofit Technology (BART) Analysis – Tri-State Craig Station Units 1 and 2*, p. 2. [EPA-R08-OAR-2018-0015-0004]

[42] U.S. EPA, Docket No. EPA-R05-OAR-2021-0963, Technical Support Document for the Federal Register Notice of the Proposed Rule for Air Plan Approval; Indiana; Regional Haze Plan for the Second Implementation Period April 22, 2025, pp. 14-15,

[43] U.S. EPA, *Carbon Dioxide Emissions*, February 23, 2025: https://www.epa.gov/ghgemissions/carbon-dioxide-emissions.

[44] IDEM, Part 70 Operating Permit Renewal (Title V), NIPSCO - R.M. Schahfer Generating Station, February 4, 2025.

[45] Ibid, p. 9.

February, and March of 2025. The basis for this projection is the operating profile of the three-unit J.H. Campbell coal plant that was scheduled to retire on May 31, 2025 but continues to operate under a 202(c) order. The plant continues to operate as it did before the Schahfer Order. In fact, the 265 MW Campbell Unit 1 actually produced more electricity in August 2025 operating under the Department of Energy's 202(c) order than it did in August 2024.[46] However, it is important to note that, as noted above, Schahfer 18 needs repairs that likely will take beyond 90 days to complete. If Schahfer 18 actually cannot operate in the 90-day period of the Schahfer Order, then the Unit 18 figures in Tables 4a and 4b below are not applicable.

51. As shown in Table 4a, if Schahfer 17 and 18 operated during the 90-day period of the Schahfer Order with the same level of production they maintained in January – March 2025, more than 140,000 pounds of SO_2, and 675,000 pounds of NO_x would be emitted over the 90-day period. As shown in Table 4b, 535,000 tons of CO_2 and nearly 104,000 pounds of PM would be emitted. None of these emissions could occur if Schahfer 17 and 18 had been permanently retired by December 31, 2025.

Table 4a. Projected Schahfer 17 and 18 SO_2, and NO_x Emissions,[47] 90-Day Order

Month	Production,[48] MWh		Fuel usage, MMBtu		SO_2 emissions, lbs	NO_x emissions, lbs
	17	18	17	18		
January 2026	98,307	136,987	1,232,386	1,265,210	67,435	324,687
February 2026	108,906	10,672	1,415,690	157,053	42,464	204,457
March 2026	84,103	0	1,124,327	0	30,357	146,163
90-day total:	291,316	144,373	3,772,403	1,422,263	140,256	675,307

Source of SO_2 and NO_x emission factors, EPA CAMPD database 2025: Schahfer 17 & 18: SO_2 = 0.027 lb/MMBtu, NO_x = 0.13 lb/MMBtu.

[46] EIA Form 923, Page 4 Generator Data, 2024 and 2025 (through September): https://www.eia.gov/electricity/data/eia923/.

[47] For Schahfer 17 and 18 fuel usage, SO_2, NO_x and CO_2 emission rates, see: EPA Clean Air Markets Pollutant Database (CAMPD) 2025: https://campd.epa.gov/data/custom-data-download.

[48] EIA-923 Monthly Generation and Fuel Consumption Time Series File, 2025 September, Page 4 – Generator Data, January – September 2025.

Table 4b. Projected Schahfer 17 and 18 CO_2 and PM emissions,[49] 90-Day Order

Month	Production, MWh		Fuel usage, MMBtu		CO_2 emissions, tons	PM emissions, lbs
	17	18	17	18		
January 2026	98,307	136,987	1,232,386	1,265,210	257,252	49,952
February 2026	108,906	10,672	1,415,690	157,053	161,993	31,455
March 2026	84,103	0	1,124,327	0	115,806	22,487
90-day total:	291,316	144,373	3,772,403	1,422,263	535,051	103,893

Sources: (1) CO_2 emission factors: EPA CAMPD database 2025, Schahfer 17 & 18: CO_2 = 0.103 tons/MMBtu (2) PM emission factors, EPA eGrid database 2021: Schahfer 17 PM = 0.020 lb/MMBtu, Schahfer 18 PM = 0.022 lb/MMBtu.

B. Culley 2:

52. The air cleaning equipment at Culley 2 includes an electrostatic precipitator (ESP), wet limestone scrubber, and low-NO_x burners with over-fire air.[50] As noted above, an ESP removes PM from the boiler exhaust gas. Wet limestone scrubbers (also known as flue gas desulfurization) remove SO_2. The low-NO_x burner system is intended to limit the amount of NO_x generated at the point of combustion in the boiler.

53. Tables 2a and 2b summarize the projected SO_2, NO_x, CO_2, and PM emissions from Culley 2 for the 90-day period from January 1, 2026 to March 31, 2026, assuming the same level of Culley 2 electricity generation as recorded in January, February, and March of 2025. The basis for this projection is the operating profile of the three-unit J.H. Campbell coal plant that was scheduled to retire on May 31, 2025 but that continues to operate under a 202(c) order. As previously noted, the operating profile of the Campbell plant post-order remains similar to its pre-order operating profile.

54. As shown in Table 5a, more than 112,000 pounds of SO_2, and 160,000 pounds of NO_x would be emitted during the 90-day Culley Order. As shown in Table 5b, more than 60,000

[49] For Schahfer 17 and 18 PM emission rates, see EPA eGrid database 2021: https://www.epa.gov/egrid/egrid-pm25

[50] IDEM, Part 70 Operating Permit Renewal (Title V), Southern Indiana Gas and Electric Company (SIGECO) F.B. Culley Generating Station, July 7, 2025, p 7.

tons of CO_2 and nearly 153,000 pounds of PM would be emitted. None of these emissions could occur if Culley 2 had been permanently retired by December 31, 2025.

Table 5a. Projected Culley 2 SO_2, and NO_x Emissions,[51] 90-Day Order

Month	Production,[52] MWh	Fuel consumption, MMBtu	SO_2 emissions, lbs	NO_x emissions, lbs
January 2026	17,922	243,238	46,215	65,674
February 2026	17,352	289,271	54,961	78,103
March 2026	2,602	59,721	11,347	16,125
90-day total:	37,876	592,229	112,524	159,902

Source of SO_2 and NO_x emission factors, EPA CAMPD database 2025: Culley 2: SO_2 = 0.19 lb/MMBtu, NO_x = 0.27 lb/MMBtu.

Table 5b. Projected Culley 2 CO_2, and PM Emissions,[53] 90-Day Order

Month	Production, MWh	Fuel consumption, MMBtu	CO_2 emissions, tons	PM emissions, lbs
January 2026	17,922	243,238	24,810	58,377
February 2026	17,352	289,271	29,506	78,103
March 2026	2,602	59,721	6,092	16,125
90-day total:	37,876	592,229	60,407	152,605

Sources: (1) CO_2 emission factors: EPA CAMPD database 2025, Culley 2: CO_2 = 0.102 tons/MMBtu (2) PM emission factor, EPA eGrid database 2021: Culley 2 PM = 0.24 lb/MMBtu.

Section 5. Easily attainable steps DOE can require to ensure Schahfer 17 and 18 operations are consistent with environmental requirements and minimize adverse environmental impacts

A. Schahfer 17 and 18:

55. MISO has forecast an adequate 2026 planning reserve margin ("PRM"), without operation of Schahfer 17 and 18 and Culley 2, to meet peak demand conditions in the winter of

[51] For Culley 2 fuel usage, SO_2, NO_x and CO_2 emission rates, see: EPA Clean Air Markets Pollutant Database (CAMPD) 2025: https://campd.epa.gov/data/custom-data-download.

[52] EIA-923 Monthly Generation and Fuel Consumption Time Series File, 2025 September, Page 4 – Generator Data, January – September 2025.

[53] For Culley 2 PM emission rate, see EPA eGrid database 2021: https://www.epa.gov/egrid/egrid-pm25.

2025-2026 and the summer of 2026.[54,55] For this reason, Schahfer 17 and 18 should only be dispatched if and when MISO forecasts the potential for actual demand to substantially exceed the normal peak forecast.

56. The Schahfer Generation Station Title V permit requires that the facility "‚ ‚ ‚ must comply with all conditions of this permit. Noncompliance with any provisions of this permit is grounds for enforcement action . . . It shall not be a defense for the Permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit."[56] As described above, NIPSCO has been limiting its operational expenditures in light of Schahfer 17 and 18's expected retirement. In my opinion, for DOE's Schahfer Order to be consistent with environmental requirements, NIPSCO must demonstrate, prior to restarting Schahfer 17 and 18, that the (1) ESPs are in sound condition, and (2) that wet limestone scrubbers and ultra-low NO_x burners are in good working order. Absent such a demonstration, DOE's order may result in power being generated in a manner inconsistent with good air pollution control practices for minimizing emissions.

[54] NERC, *2025–2026 Winter Reliability Assessment*, November 2025, p. 11 and p. 17. The MISO anticipated reserve margin in the winter of 2025-2026 is 49.5%, compared to a reference margin level (RML) of ~40%.

[55] NERC, *2024 Long-Term Reliability Assessment, December 2024* (corrected July 11, 2025), Figure 3: MISO Planning Reserve Margin–Summer, p. 13. The 2026 summer anticipated (planning) reserve margin is 17%, compared to a RML, the minimum adequate PRM, of 9%. "To establish the RMLs that define the minimum (planning) reserve margins for resource adequacy, MISO performs its annual probabilistic Loss-of-Load Expectation (LOLE) Study per MISO tariff. The study produces seasonal RMLs for the upcoming planning year that are used in MISO's planning resource auction. These RMLs are calculated such that they define the minimum PRM that will meet a LOLE of 1 day in 10 years."

[56] IDEM, Part 70 Operating Permit Renewal (Title V), NIPSCO - R.M. Schahfer Generating Station, February 4, 2025, p. 1.

57. Problems with the ESPs on Schahfer 17 and 18, including broken high voltage wires and flyash buildup, have been the source of repeated outages in the last two years.[57] Regular replacement of broken ESP wires is necessary to assure good performance of the ESP. Typical operational problems with wet limestone scrubbers include: scale formation in the scrubber vessels, poor utilization of the limestone reagent, and inadequate spray nozzle efficiency.[58] Regular maintenance of (1) spray nozzles to address plugging and wear, and (2) limestone grinding mills to assure an optimum limestone particle size, is essential to maintaining the control efficiency of the wet scrubber. Ultra-low NO_x burners are subject to degradation from (1) erosion wear at the burner tip and (2) less than optimum pulverized coal combustion efficiency due to wear in the coal pulverizers.[59] Regular maintenance of the ultra-low NO_x burners and the associated coal pulverizers is essential to minimize NO_x formation in the boiler.

58. I could not locate information in the public record on (1) the condition of the Schahfer 17 and 18 ESPs, (2) the operational history and current condition of the Schahfer 17 and 18 wet limestone scrubbers, or (3) the Schahfer 17 and 18 ultra-low NO_x burners and overfire air system. 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.

59. It is my opinion that 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

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[57] IURC Cause Nos. 38706 FAC 142 and FAC 143, Direct Testimony of David Saffran on behalf of NIPSCO (Q4, 2023 and Q1, 2024), Att. 4-A, at 1. "Two years" refers to the two most recent years of available outage records, from Q4 2023 through Q3 2025.

[58] Power Engineering, *Wet-Limestone Scrubbing Fundamentals*, August 1, 2006: https://www.power-eng.com/operations-maintenance/wet-limestone-scrubbing-fundamentals/.

[59] Power Magazine, *To optimize performance, begin at the pulverizers*, February 2007; Riley Power, *Advanced Erosion Protection Technology Provides Sustained Low NOx Burner Performance*, April 2004.

operate under extreme demand conditions. DOE should also require that if air permit limits for PM, NO_x, or SO_2 are exceeded during operation of Schahfer 17 and 18, as registered on the continuous PM, NO_x, or SO_2 monitors installed on the units, then unit(s) will be shut down.

60. It is also my opinion that there are alternatives to running Schahfer 17 and 18 to meet an extreme peak demand that would produce far less environmental harm. As previously noted, battery storage and (natural gas and oil-fired) combustion gas turbines are examples of resources that are ideally suited to addressing rapidly varying, peak demand conditions. Hydropower can also respond quickly to changing demand conditions. In 2026, NIPSCO will have at its disposal 563 MW of gas -fired generation, 16 MW of hydropower, and approximately 620 MW of demand response to address fast-changing demand on its system.[60]

61. Any air emissions that result from running Schahfer 17 and 18 would not occur if the units are retired. Additionally, Schahfer 17 and 18 consume approximately 21.7 million gallons of water per day of operation at their combined net capacity of 722 MW.[61]

62. Finally, any coal burned will produce coal ash that will have to be stored/disposed of onsite. That is an additional impact that would not occur if Schahfer 17 and 18 are retired. The EPA's 2015 CCR (Coal Combustion Residuals) Rule regulates CCRs.[62] NIPSCO has completed several CCR projects and has active ongoing projects to comply with the 2015 CCR Rule.[63] NIPSCO states that retirement of Schahfer Generating Station Units 17 and 18 by 2025

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[60] NIPSCO 2024 IRP at Summary p. 7; NIPSCO 2025-2026 Planning Reserve Margin Report, p. 4.

[61] IDEM, NPDES Permit No. IN0053201, Northern Indiana Public Service Company LLC - R. M. Schahfer Generating Station, September 24, 2020, pdf p. 57 ("The R.M. Schahfer facility's design intake flow (DIF) rate is 57.7 MGD, almost all of which is used for non-contact cooling water.") and p. 94 ("For the period 2015 through 2019, the actual intake flow (AIF) was 21.7 MGD.").

[62] NIPSCO 2024 IRP, p. 204.

[63] NIPSCO, (webpage) Data and information about CCRs, 2026: https://www.nipsco.com/our-company/about-us/our-environment/ccr-rule-compliance.

will avoid significant capital cost needed to comply with the 2015 CCR Rule and other environmental requirements.[64]

B. Culley 2:

63. Again, MISO has forecast an adequate 2026 PRM without operation of Culley 2 and Schahfer units 17 and 18 to meet peak demand conditions.[65]

64. The Culley Generation Station Title V permit requires that the facility will operate "in accordance with good air pollution control practices for minimizing excess emissions."[66] The Title V permit also requires that the ESP be operated at all times Unit 2 is combusting coal "to maximize PM emission reductions, consistent with the operational and maintenance limitations of the unit."[67] In my opinion, for DOE's Order to be consistent with environmental requirements, CEIS must demonstrate, prior to restarting Culley 2, that the (1) ESP is in sound condition, and (2) that wet limestone scrubber and ultra-low NO_x burners are in good working order. Absent such a demonstration, DOE's order may result in power being generated in a manner inconsistent with good air pollution control practices for minimizing emissions.

65. Problems with the ESPs include broken wires that compromise performance and ash build-up caused by flyash removal difficulties.[68] Regular replacement of broken ESP wires is necessary to assure good performance of the ESP. Again, typical operational problems with wet limestone scrubbers include: scale formation in the scrubber vessels, poor utilization of the

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[64] NIPSCO 2024 IRP, p. 204.

[65] OMS and MISO, *OMS-MISO Survey Results* (Updated June 6, 2025), https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf.

[66] Culley Generating Station Title V air permit, July 7, 2025, p. 30.

[67] Ibid, p. 39.

[68] See (for representative examples of ESP problems): IURC Cause Nos. 38706 FAC 142 and FAC 143, Direct Testimony of David Saffran on behalf of NIPSCO (Q4, 2023 and Q1, 2024), Att. 4-A, at 1.

limestone reagent, and inadequate spray nozzle efficiency.[69] Regular maintenance of (1) spray nozzles to address plugging and wear, and (2) limestone grinding mills to assure an optimum limestone particle size, is essential to maintaining the control efficiency of the wet scrubber. Ultra-low NO_x burners are subject to degradation from (1) erosion wear at the burner tip and (2) less than optimum pulverized coal combustion efficiency due to wear in the coal pulverizers.[70] Regular maintenance of the ultra-low NO_x burners and the associated coal pulverizers is essential to minimize NO_x formation in the boiler.

66. I could not locate information in the public record on (1) the condition of the Culley 2 ESP, (2) the operational history and current condition of the Culley 2 wet limestone scrubber, or (3) the Culley 2 ultra-low NO_x burners and overfire air system. It cannot be assumed that the Culley 2 pollution control equipment is in good working order and will operate reliably to control the facility's emissions beyond December 2025.

67. It is my opinion that DOE should require verification of the good working order of the Culley 2 air emission control systems before authorizing Culley 2 to operate under extreme demand conditions. DOE should also require that if air permit limits for PM, NO_x, or SO_2 are exceeded during operation of Culley 2, as registered on the continuous PM, NO_x, or SO_2 monitors installed on the units, then unit will be shut down.

68. It is also my opinion that there are alternatives to running Culley 2 to meet an extreme peak demand that would produce far less environmental harm. As previously noted, battery storage and combustion gas turbines are examples of resources that are ideally suited to

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[69] Power Engineering, *Wet-Limestone Scrubbing Fundamentals*, August 1, 2006: https://www.power-eng.com/operations-maintenance/wet-limestone-scrubbing-fundamentals/.

[70] Power Magazine, *To optimize performance, begin at the pulverizers*, February 2007; Riley Power, *Advanced Erosion Protection Technology Provides Sustained Low NOx Burner Performance*, April 2004.

addressing rapidly varying, peak demand conditions. CEIS recently built the new A.B. Brown combustion turbine plant (460 megawatts), which reached commercial operation in 2025.[71]

69. Any air emissions that result from running Culley 2 would not occur if the plant is retired.

70. Additionally, Culley 2 uses a once-through cooling system drawing water from the Ohio River. The Culley 2 water withdrawal rate is approximately 45 million gallons per day on average.[72]

72. Finally, any coal burned will produce coal ash that will have to be stored/disposed of onsite. That is an additional impact that would not occur if Culley 2 is retired.

73. In my opinion, a coal unit would be the last alternative to consider for a peaking power application due to its slow ramp rate and high environmental impact.

I declare under penalty of perjury under the laws of the United States, pursuant to 28 U.S.C. § 1746, that the foregoing is true and correct to the best of my knowledge.

Executed on this 21 day of January 2026, in San Diego, California.

Bill Powers, P.E.

Bill Powers, P.E.
Powers Engineering
4452 Park Blvd., Suite 209
San Diego, CA 92116

[71] CEIS 2025 IRP, p. 12.

[72] IDEM, NPDES Permit No. IN0002259 Permit Modification, SIGECO F.B. Culley Generating Station, May 3, 2024, pdf p. 44. Average once through cooling outfall flow to the Ohio River is 181.6 million gallons per day (MGD). 90 MW Unit 2 is 25% of the combined capacity of 90 MW Unit 2 and 270 MW Unit 3. Therefore, assume the average Unit 2 cooling water flow = 0.25 × 181.6 MGD = 45.4 MGD.

Attachment A

BILL POWERS, P.E.

PROFESSIONAL HISTORY

Powers Engineering, San Diego, CA 1994-
ENSR Consulting and Engineering, Camarillo, CA 1989-93
Naval Energy and Environmental Support Activity, Port Hueneme, CA 1982-87
U.S. Environmental Protection Agency, Research Triangle Park, NC 1980-81

EDUCATION

Bachelor of Science – Mechanical Engineering, Duke University
Master of Public Health – Environmental Sciences, University of North Carolina

PROFESSIONAL AFFILIATIONS

Registered Professional Mechanical Engineer, California (Certificate M24518)
Registered Professional Engineer, Missouri (Certificate 2018039156)
American Society of Mechanical Engineers
Institute of Electrical and Electronics Engineers

TECHNICAL SPECIALTIES

Forty years of experience in:

- Air quality and utility commission proceedings - expert witness
- Distributed solar photovoltaics (PV) siting and regional renewable energy planning
- Power plant cooling system conversion and air emission control assessments
- Combustion equipment permitting, testing and monitoring
- Air pollution control equipment retrofit design/performance testing
- Petroleum refinery air engineering and testing
- Latin America environmental project experience

RECENT AIR QUALITY AND UTILITY COMMISSION PROCEEDINGS

Compressor Station Gas Turbine Air Emission Controls. Assessed the air emission controls and siting issues related to two proposed pipeline compressor station projects in the vicinity of Nashville, Tennessee utilizing Solar Turbines, Inc Titan gas turbines. The result, based on application of a Reasonably Available Control Technology (RACT) requirement, was the reduction of the proposed air permit nitrogen oxides (NOx) emission limit from 25 parts per million (ppm) to 9 ppm.

Combined Heat and Power Plant Gas Turbine Air Emission Controls. Evaluated the air emission controls proposed for a combined heat and power (CHP) plant at Duke University that would utilize Solar Turbines, Inc Titan gas turbine. Applicant proposed a 25 ppm NO_x limit using dry low-NO_x combustion as Best Available Control Technology (BACT) in its Certificate of Public Convenience and Necessity (CPCN) application to the North Carolina Utilities Commission. Argued that NO_x BACT for the CHP plant should be use of selective catalytic reduction (SCR) to achieve a 2 ppm NO_x emission limit. Applicant withdrew its CPCN application.

SDG&E 36-Inch Transmission Pipeline. Expert witness for non-profit client advocating that existing 16-inch pipeline did not require replacement with new $600 million 36-inch pipeline. Underscored in testimony that SDG&E had recently completed extensive inline inspection of existing 16-inch pipeline and found that pipeline was in good condition for long-term operation at 512 psig transmission pressure. Demonstrated that reduction of pressure to 320 psig would not increase safety of existing pipeline, as ILI could no longer be done periodically at lower pressure. Commission accepted this reasoning and denied SDG&E's application.

Cove Point LNG Export Terminal. Expert witness in two separate administrative proceedings before the Maryland Public Service Commission, in 2014 and 2017, regarding air permit conditions for the proposed Cove Point LNG export. The plant site is located in a non-attainment area for ozone. Testimony addressed deficiencies in the proposed air emission limits and proposed control technology for combustion equipment – including gas turbines, auxiliary boilers, and flares, fugitive emission sources, and marine loading vapor recovery systems.

Corpus Christi LNG Expert Terminal. Expert witness in Texas Commission on Environmental Quality contested air permit proceeding in 2013 before the State Office of Administrative Hearings. Testimony addressed deficiencies in the proposed control technology for compressor-drive gas turbines, flares, and fugitive emission sources, and marine loading vapor recovery systems.

DISTRIBUTED SOLAR PV SITING AND REGIONAL RENEWABLE ENERGY PLANNING

Roadmap to 100 Percent Local Solar by 2030 in the City of San Diego. Author of the May 2020 *Roadmap to 100 Percent Local Solar Build-Out by 2030 in the City of San Diego* strategic energy plan for San Diego. The *Roadmap* outlines a strategy to maximize the use of solar energy and battery storage in the City of San Diego (City) to provide 100 percent clean electricity to all San Diegans by 2030. The City's Climate Action Plan sets a mandatory target of 100 percent clean electricity by 2035. The *Roadmap* describes how the City can best deliver lower-cost electricity and provide local job growth by choosing local solar power paired with battery storage, complemented by smart energy efficiency and demand response programs, to reach 100 percent clean energy.

North Carolina Clean Path 2025 Plan. Author of the August 2017 *North Carolina Clean Path 2025* strategic energy plan for North Carolina. *NC Clean Path 2025* implements local solar power, battery storage, and energy efficiency measures to rapidly replace fossil fuel-generated electricity in the state. The plan is substantially less costly than the $40 billion expansion of natural gas infrastructure, nuclear power, and transmission infrastructure being planned for North Carolina. Implementation of *NC Clean Path 2025* would reduce power generated by coal- and natural gas-fired plants by about 60 percent by 2025, and 100 percent by 2030. All in-state coal-fired plants would be closed and gas-fired plants would be used only for backup supply. Existing transmission and distribution infrastructure would be maintained and not expanded.

Bay Area Smart Energy 2020 Plan. Author of the March 2012 *Bay Area Smart Energy 2020* strategic energy plan for the nine-county region surrounding San Francisco Bay. This plan uses the zero net energy building targets in the *California Energy Efficiency Strategic Plan* as a framework to achieve a 60 percent reduction in GHG emissions from Bay Area electricity usage, and a 50 percent reduction in peak demand for grid electricity, by 2020. The 2020 targets in the plan include: 25 percent of detached homes and 20 percent of commercial buildings achieving zero net energy, adding 200 MW of community-scale microgrid battery storage and 400 MW of utility-scale battery storage, reduction in air conditioner loads by 50 percent through air conditioner cycling and targeted incentive funds to assure highest efficiency replacement units, and cooling system modifications to increase power output from The Geysers geothermal production zone in Sonoma County.

Solar PV technology selection and siting for SDG&E Solar San Diego project. Served as PV technology expert in California Public Utilities Commission proceeding to define PV technology and sites to be used in San Diego Gas & Electric (SDG&E) $250 million "Solar San Diego" project. Recommendations included: 1) prioritize use of roof-mounted thin-film PV arrays similar to the SCE urban PV program to maximize the installed PV capacity, 2) avoid tracking ground-mounted PV arrays due to high cost and relative lack of available land in the urban/suburban core, 3) and incorporate limited storage in fixed rooftop PV arrays to maximizing output during peak demand periods. Suitable land next to SDG&E substations capable of supporting 5 to 40 MW of PV (each) was also identified by Powers Engineering as a component of this project.

Rooftop PV alternative to natural gas-fired peaking gas turbines, Chula Vista. Served as PV technology expert in California Energy Commission (CEC) proceeding regarding the application of MMC Energy to build a 100 MW peaking gas turbine power plant in Chula Vista. Presented testimony that 100 MW of PV arrays in the Chula Vista area could provide the same level of electrical reliability on hot summer days as an equivalent amount of peaking gas turbine capacity at approximately the same cost of energy. The final decision issued by the CEC in the case denied the application in part due to failure of the applicant or CEC staff to thoroughly evaluate the PV alternative to the proposed turbines.

San Diego Smart Energy 2020 Plan. Author of October 2007 *San Diego Smart Energy 2020*, an energy plan that focuses on meeting the San Diego region's electric energy needs through accelerated integration of renewable and non-renewable distributed generation, in the form of combined heat and power (CHP) systems and solar photovoltaic (PV) systems. PV would meet approximately 28 percent of the San Diego region's electric energy demand in 2020. Annual energy demand would drop 20 percent in 2020 relative to 2003 through use all cost-effective energy efficiency measures. Existing utility-scale gas-fired generation would continue to be utilized to provide power at night, during cloudy weather, and for grid reliability support.

COOLING SYSTEM CONVERSION AND POWER PLANT EMISSION CONTROL ASSESSMENTS

Closed-Cycle Cooling Alternative at California Nuclear Plant.
Lead engineer on review of Bechtel assessment of wedgewire screens and closed-cycle cooling for Diablo Canyon nuclear plant. Demonstrated that wedgewire screens were not likely to be effective in substantially reducing entrainment at the site, and that lower cost closed-cycle retrofit alternatives could be utilized to allow a "cost reasonable" cooling tower retrofit. Plume-abated back-to-back cooling towers located in secondary parking lots to the southeast of the turbine building were identified as the most cost-effective alternative.

Closed-Cycle Cooling Alternative at Florida Nuclear Plant.
Evaluated closed cycle cooling tower feasibility assessment for Turkey Point Nuclear Units 3 and 4. Closed-cycle cooling would replace the existing closed-cycle cooling canals. Wet cooling towers for Units 3 and 4 are feasible and could be operational within four years of submittal of applications for the necessary permits.

Utility Boilers – Conversion of Existing Once-Through Cooled Boilers to Wet Towers, Parallel Wet-Dry Cooling, or Dry Cooling. Provided expert testimony and preliminary design for the conversion of four natural gas and/or coal-fired utility boilers (Unit 4, 235 MW; Unit 3, 135 MW; Unit 2, 65 MW; and Unit 1,65 MW) from once-through river water cooling to wet cooling towers, parallel wet-dry cooling, and dry cooling. Major design constraints were available land for location of retrofit cooling systems and need to maintain maximum steam turbine backpressure at or below 5.5 inches mercury to match performance capabilities of existing equipment. Approach temperatures of 12 ºF and 13 ºF were used for the wet towers. SPX Cooling Technologies F-488 plume-abated wet cells with six feet of packing were used to achieve approach temperatures of 12 ºF and 13 ºF. Annual energy penalty of wet tower retrofit designs is approximately 1 percent. Parallel wet-dry or dry cooling was determined to be technically feasible for Unit 3 based on straightforward access to the Unit 3 surface condenser and available land adjacent to the boiler.

Utility Boiler – Assessment of Air Cooling and Integrated Gasification/Combined Cycle for Proposed 500 MW Coal-Fired Plant. Provided expert testimony on the performance of air-cooling and IGCC relative to the conventional closed-cycle wet cooled, supercritical pulverized coal boiler proposed by the applicant. Steam Pro™ coal-fired power plant design software was used to model the proposed plant and evaluate the impacts on performance of air cooling and plume-abated wet cooling. Results indicated that a conservatively designed air-cooled condenser could maintain rated power output at the design ambient temperature of 90 ºF. The IGCC comparative analysis indicated that unit reliability comparable to a conventional pulverized coal unit could be achieved by including a spare gasifier in the IGCC design, and that the slightly higher capital cost of IGCC was offset by greater thermal efficiency and reduced water demand and air emissions.

Utility Boiler – Assessment of Closed-Cycle Cooling Retrofit Cost for 1,200 MW Oil-Fired Plant. Prepared an assessment of the cost and feasibility of a closed-cycle wet tower retrofit for the 1,200 MW Roseton Generating Station. Determined that the cost to retrofit the Roseton plant with plume-abated closed-cycle wet cooling was well established based on cooling tower retrofit studies performed by the original owner (Central Hudson Gas & Electric Corp.) and subsequent regulatory agency critique of the cost estimate. Also determined that elimination of redundant and/or excessive budgetary line items in owners cost estimate brings the closed-cycle retrofit in line with expected costs for comparable new or retrofit plume-abated cooling tower applications.

Nuclear Power Plant – Assessment of Closed-Cycle Cooling Retrofit Cost for 2,000 MW Plant. Prepared an assessment of the cost and feasibility of a closed-cycle wet tower retrofit for the 2,000 MW Indian Point Generating Station. Determined that the most appropriate arrangement for the hilly site would be an inline plume-abated wet tower instead of the round tower configuration analyzed by the owner. Use of the inline configuration would allow placement of the towers at numerous sites on the property with little or need for blasting of bedrock, greatly reducing the cost of the retrofit. Also proposed an alternative circulating cooling water piping configuration to avoid the extensive downtime projected by the owner for modifications to the existing discharge channel.

Power Plant Dry Cooling Symposium – Chair and Organizer. Chair and organizer of the first symposium held in the U.S. (May 2002) that focused exclusively on dry cooling technology for power plants. Sessions included basic principles of wet and dry cooling systems, performance capabilities of dry cooling systems, case studies of specific installations, and reasons why dry cooling is the predominant form of cooling specified in certain regions of North America (Massachusetts, Nevada, northern Mexico).

Ameren Missouri Coal Units – Causes of Opacity and Opacity Reduction Alternatives. Lead engineer to assess the root causes of opacity exceedances and evaluate potential alternatives to eliminate opacity violations from the Labadie, Meramec, and Rush Island power plants.

Utility Boilers – Evaluation of Correlation Between Opacity and PM_{10} Emissions at Coal-Fired Plant. Provided expert testimony on whether correlation existed between mass PM_{10} emissions and opacity during opacity excursions at large coal-fired boiler in Georgia. EPA and EPRI technical studies were reviewed to assess the correlation of opacity and mass emissions during opacity levels below and above 20 percent. A strong correlation between opacity and mass emissions was apparent at a sister plant at opacities less than 20 percent. The correlation suggests that the opacity monitor correlation underestimates mass emissions at opacities greater than 20 percent, but may continue to exhibit a good correlation for the component of mass emissions in the PM_{10} size range.

IGCC as BACT for Air Emissions from Proposed 960 MW Coal Plant. Presented testimony on IGCC as BACT for air emissions reduction from 960 MW coal plant. Applicant received air permit for a pulverized coal plant to be equipped with a baghouse, wet scrubber, and wet ESP for air emissions control. Use of IGCC technology at the emission rates permitted for two recently proposed U.S. IGCC projects, and demonstrated in practice at a Japanese IGCC plant firing Chinese bituminous coal, would substantially reduce potential emissions of NO_x, SO_2, and PM. The estimated control cost-effectiveness of substituting IGCC for pulverized coal technology in this case was approximately $3,000/ton.

Analysis of Proposed Air Emission Limits for 600 MW Pulverized Coal Plant. Project engineer tasked with evaluating sufficiency of air emissions limits and control technologies for proposed 600 MW coal plant Arkansas. Determined that the applicant had: 1) not properly identified SO_2, sulfuric acid mist, and PM BACT control levels for the plant, and 2) improperly utilized an incremental cost effectiveness analysis to justify air emission control levels that did not represent BACT.

Eight Pulverized Coal Fired 900 MW Boilers – IGCC Alternative with Air Cooling. Provided testimony on integrated gasification combined cycle (IGCC) as a fully commercial coal-burning alternative to the pulverized coal (PC) technology proposed by TXU for eight 900 MW boilers in East Texas, and East Texas as an ideal location for CO2 sequestration due to presence of mature oilfield CO2 enhanced oil recovery opportunities and a deep saline aquifer underlying the entire region. Also presented testimony on the major increase in regional consumptive water use that would be caused by the evaporative cooling towers proposed for use in the PC plants, and that consumptive water use could be lowered by using IGCC with evaporative cooling towers or by using air-cooled condensers with PC or IGCC technology. TXU ultimately dropped plans to build the eight PC plants as a condition of a corporate buy-out.

Utility Boilers – Retrofit of SCR and FGD to Existing Coal-Fired Units.
Expert witness in successful effort to compel an existing coal-fired power plant located in Massachusetts to meet an accelerated NO_x and SO_2 emission control system retrofit schedule. Plant owner argued the installation of advanced NO_x and SO_2 control systems would generate > 1 ton/year of ancillary emissions, such as sulfuric acid mist, and that under Massachusetts Dept. of Environmental Protection regulation ancillary emissions > 1 ton/year would require a BACT evaluation and a two-year extension to retrofit schedule. Successfully demonstrated that no ancillary emissions would be generated if the retrofit NO_x and SO_2 control systems were properly sized and optimized. Plant owner committed to accelerated compliance schedule in settlement agreement.

Utility Boilers – Retrofit of SCR to Existing Natural Gas-Fired Units.
Lead engineer in successful representation of interests of California coastal city to prevent weakening of an existing countywide utility boiler NO_x rule. Weakening of NO_x rule would have allowed a merchant utility boiler plant located in the city to operate without installing selective catalytic reduction (SCR) NO_x control systems. This project required numerous appearances before the county air pollution control hearing board to successfully defend the existing utility boiler NO_x rule.

Biomass Plant NO_x and CO Air Emissions Control Evaluation. Lead engineer for evaluation of available nitrogen oxide (NO_x) and carbon monoxide (CO) controls for a 45 MW Aspen Power biomass plant in Texas where proponent had identified selective non-catalytic reduction (SNCR) for NO_x and good combustion practices for CO as BACT. Identified the use of tail-end SCR for NO_x control at several operational U.S. biomass plants, and oxidation catalyst in use at two of these plants for CO and VOC control, as BACT for the proposed biomass plant. Administrative law judge concurred in decision that SCR and oxidation catalyst is BACT. Developer added SCR and oxidation catalyst to project in subsequent settlement agreement.

Biomass Plant Air Emissions Control Consulting. Lead expert on biomass air emissions control systems for landowners that will be impacted by a proposed 50 MW biomass to be built by the local East Texas power cooperative. Public utility agreed to meet current BACT for biomass plants in Texas, SCR for NO_x and oxidation catalyst for CO, in settlement agreement with local landowners.

Combined-Cycle Power Plant Startup and Shutdown Emissions. Lead engineer for analysis of air permit startup and shutdown emissions minimization for combined-cycle power plant proposed for the San Francisco Bay Area. Original equipment was specified for baseload operation prior to suspension of project in early 2000s. Operational profile described in revised air permit was load following with potential for daily start/stop. Recommended that either fast start turbine technology be employed to minimize start/stop emissions or that "demonstrated in practice" operational and control software modifications be employed to minimize startup/shutdown emissions.

NON-WIRES ALTERNATIVES TO TRANSMISSION LINES

Ameren Missouri Mark Twain 345 kV Transmission Line. Responsible for evaluating: 1) the expected peak load growth of Ameren Missouri (MO) in general and in Northeast MO specifically over the next decade, 2) the likelihood of wind projects moving forward in the Northeast MO over the next decade, 3) the feasibility and cost of reconductoring with high capacity composite conductors the three 161 kV line segments that would experience NERC violations if 450 to 500 MW of wind power was constructed in Northeast MO, and 4) the feasibility and cost-effectiveness of substituting local solar for wind power to allow Ameren MO to meet its 2021 Renewable Portfolio Standard (RPS) obligation without building the proposed 345 kV transmission line or upgrading the three existing 161 kV lines interconnecting at the Adair Substation.

American Transmission Corporation Badger-Coulee 345 kV Line. Responsible for evaluating: 1) the expected peak load growth of Wisconsin utilities over the next decade, and 2) the feasibility and cost-effectiveness of alternatives including load management, energy efficiency, local solar, biogas, and energy storage as viable no-wires alternatives to the proposed ATC Badger-Coulee 345 kV transmission line.

San Diego Gas & Electric Wood Pole to Steel Pole Replacement Project.
Lead engineer assessing need and alternatives to replacement of existing wooden 69 kV poles with larger steel 69 kV poles as a response to the fire hazard potential of wooden poles in rural, high fire risk areas. Wooden poles in good condition and not a source of fire ignition. Utility would continue to shut off power to customers during low humidity, high wind conditions. Prepared alternative, solar with batteries for the ~10,000 affected customer meters, to allow customers to ride-through high fire hazard preventive grid power shut-offs at far less cost than replacing wood poles with steel poles.

San Diego Gas & Electric 500 kV Sunrise Transmission Line.
Lead engineer assessing the validity of load growth forecasts used by the utility to justify the need for the 500 kV line, and for developing a no-wires alternative, net-metered solar power with some battery support, to meet the identified reliability need at little or no net cost to the utility customer base.

COMBUSTION EQUIPMENT PERMITTING, TESTING AND MONITORING

EPRI Gas Turbine Power Plant Permitting Documents – Co-Author.
Co-authored two Electric Power Research Institute (EPRI) gas turbine power plant siting documents. Responsibilities included chapter on state-of-the-art air emission control systems for simple-cycle and combined-cycle gas turbines, and authorship of sections on dry cooling and zero liquid discharge systems.

Air Permits for 50 MW Peaker Gas Turbines – Six Sites Throughout California.
Responsible for preparing all aspects of air permit applications for five 50 MW FT-8 simple-cycle turbine installations at sites around California in response to emergency request by California state government for additional peaking power. Units were designed to meet 2.0 ppm NO_x using standard temperature SCR and innovative dilution air system to maintain exhaust gas temperature within acceptable SCR range. Oxidation catalyst is also used to maintain CO below 6.0 ppm.

Kauai 27 MW Cogeneration Plant – Air Emission Control System Analysis. Project manager to evaluate technical feasibility of SCR for 27 MW naphtha-fired turbine with once-through heat recovery steam generator. Permit action was stalled due to questions of SCR feasibility. Extensive analysis of the performance of existing oil-fired turbines equipped with SCR, and bench-scale tests of SCR applied to naphtha-fired turbines, indicated that SCR would perform adequately. Urea was selected as the SCR reagent given the local availability of urea. Unit is first known application of urea-injected SCR on a naphtha-fired turbine.

Microturbines – Ronald Reagan Library, Ventura County, California.
Project manager and lead engineer or preparation of air permit applications for microturbines and standby boilers. The microturbines drive the heating and cooling system for the library. The microturbines are certified by the manufacturer to meet the 9 ppm NO_x emission limit for this equipment. Low-NO_x burners are BACT for the standby boilers.

Hospital Cogeneration Microturbines – South Coast Air Quality Management District. Project manager and lead engineer for preparation of air permit application for three microturbines at hospital cogeneration plant installation. The draft Authority To Construct (ATC) for this project was obtained two weeks after submittal of the ATC application. 30-day public notification was required due to the proximity of the facility to nearby schools. The final ATC was issued two months after the application was submitted, including the 30-day public notification period.

Gas Turbine Cogeneration – South Coast Air Quality Management District. Project manager and lead engineer for preparation of air permit application for two 5.5 MW gas turbines in cogeneration configuration for county government center. The turbines are equipped with selective catalytic reduction (SCR) and oxidation catalyst to comply with SCAQMD BACT requirements. Aqueous urea is used as the SCR reagent to avoid trigger hazardous material storage requirements. The NO_x and CO continuous emissions monitoring systems are covered by a separate permit.

Peaker Gas Turbines – Evaluation of NO_x Control Options for Installations in San Diego County. Lead engineer for evaluation of NO_x control options available for 1970s vintage simple-cycle gas turbines proposed for peaker sites in San Diego County. Dry low-NO_x (DLN) combustors, catalytic combustors, high-temperature SCR, and NO_x absorption/conversion ($SCONO_x$) were evaluated for each candidate turbine make/model. High-temperature SCR was selected as the NOx control option to meet a 5 ppm NO_x emission requirement.

Hospital Cogeneration Plant Gas Turbines – San Joaquin Valley Unified Air Pollution Control District. Project manager and lead engineer for preparation of air permit application and Best Available Control Technology (BACT) evaluation for hospital cogeneration plant installation. The BACT included the review of DLN combustors, catalytic combustors, high-temperature SCR and $SCONO_x$. DLN combustion followed by high temperature SCR was selected as the NO_x control system for this installation. The high temperature SCR is located upstream of the heat recovery steam generator (HRSG) to allow the diversion of exhaust gas around the HRSG without compromising the effectiveness of the NO_x control system.

1,000 MW Coastal Combined-Cycle Power Plant – Feasibility of Dry Cooling. Expert witness in on-going effort to require use of dry cooling on proposed 1,000 MW combined-cycle "repower" project at site of an existing 1,000 MW utility boiler plant. Project proponent argued that site was two small for properly sized air-cooled condenser (ACC) and that use of ACC would cause 12-month construction delay. Demonstrated that ACC could easily be located on the site by splitting total of up to 80 cells between two available locations at the site. Also demonstrated that an ACC optimized for low height and low noise would minimize or eliminate proponent claims of negative visual and noise impacts.

Industrial Cogeneration Plant Gas Turbines – Upgrade of Turbine Power Output. Project manager and lead engineer for preparation of Best Available Control Technology (BACT) evaluation for proposed gas turbine upgrade. The BACT included the review of DLN combustors, catalytic combustors, high-, standard-, and low-temperature SCR, and $SCONO_x$. Successfully negotiated air permit that allowed facility to initially install DLN combustors and operate under a NO_x plantwide "cap." Within two major turbine overhauls, or approximately eight years, the NO_x emissions per turbine must be at or below the equivalent of 5 ppm. The 5 ppm NO_x target will be achieved through technological in-combustor NO_x control such as catalytic combustion, or SCR or SCR equivalent end-of-pipe NO_x control technologies if catalytic combustion is not available.

Gas Turbines – Modification of RATA Procedures for Time-Share CEM. Project manager and lead engineer for the development of alternate CO continuous emission monitor (CEM) Relative Accuracy Test Audit (RATA) procedures for time-share CEM system serving three 7.9 MW turbines located in San Diego. Close interaction with San Diego APCD and EPA Region 9 engineers was required to receive approval for the alternate CO RATA standard. The time-share CEM then passed the annual RATA without problems as a result of changes to some CEM hardware and the more flexible CO RATA standard.

Gas Turbines – Evaluation of NO_x Control Technology Performance. Lead engineer for performance review of dry low-NO_x combustors, catalytic combustors, high-, standard-, and low-temperature selective catalytic reduction (SCR), and NO_x absorption/conversion (SCONO$_x$). Major turbine manufacturers and major manufacturers of end-of-pipe NO_x control systems for gas turbines were contacted to determine current cost and performance of NO_x control systems. A comparison of 1993 to 1999 "$/kwh" and "$/ton" cost of these control systems was developed in the evaluation.

Lead engineer for evaluation for proposed combined cycle gas turbine NO_x and CO control systems. Project was in litigation over contract terms, and there was concern that the GE Frame 7FA turbine could not meet the 3 ppm NO_x permit limit using a conventional combustor with water injection followed by SCR. Operations personnel at GE Frame 7FA installatins around the country were interviewed, along with principal SCR vendors, to corroborate that the installation could continuously meet the 3 ppm NO_x limit.

Gas Turbines – Title V "Presumptively Approvable" Compliance Assurance Monitoring Protocol. Project manager and lead engineer for the development of a "presumptively approval" NO_x parametric emissions monitoring system (PEMS) protocol for industrial gas turbines. "Presumptively approvable" means that any gas turbine operator selecting this monitoring protocol can presume it is acceptable to the U.S. EPA. Close interaction with the gas turbine manufacturer's design engineering staff and the U.S. EPA Emissions Measurement Branch (Research Triangle Park, NC) was required to determine modifications necessary to the current PEMS to upgrade it to "presumptively approvable" status.

Environmental Due Diligence Review of Gas Turbine Sites – Mexico. Task leader to prepare regulatory compliance due diligence review of Mexican requirements for gas turbine power plants. Project involves eleven potential sites across Mexico, three of which are under construction. Scope involves identification of all environmental, energy sales, land use, and transportation corridor requirements for power projects in Mexico. Coordinator of Mexican environmental subcontractors gathering on-site information for each site, and translator of Spanish supporting documentation to English.

Development of Air Emission Standards for Gas Turbines - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian gas turbine power plants. All major gas turbine power plants in Peru are currently using water injection to increase turbine power output. Recommended that 42 ppm on natural gas and 65 ppm on diesel (corrected to 15% O_2) be established as the NO_x limit for existing gas turbine power plants. These limits reflect NO_x levels readily achievable using water injection at high load. Also recommended that new gas turbine sources be subject to a BACT review requirement.

Gas Turbines – Title V Permit Templates. Lead engineer for the development of standardized permit templates for approximately 100 gas turbines operated by the oil and gas industry in the San Joaquin Valley. Emissions limits and monitoring requirements were defined for units ranging from GE Frame 7 to Solar Saturn turbines. Stand-alone templates were developed based on turbine size and NO_x control equipment. NO_x utilized in the target turbine population ranged from water injection alone to water injection combined with SCR.

Gas Turbines – Evaluation of NO_x, SO_2 and PM Emission Profiles. Performed a comparative evaluation of the NO_x, SO_2 and particulate (PM) emission profiles of principal utility-scale gas turbines for an independent power producer evaluating project opportunities in Latin America. All gas turbine models in the 40 MW to 240 MW range manufactured by General Electric, Westinghouse, Siemens and ABB were included in the evaluation.

Stationary Internal Combustion Engine (ICE) RACT/BARCT Evaluation. Lead engineer for evaluation of retrofit NO_x control options available for the oil and gas production industry gas-fired ICE population in the San Joaquin Valley affected by proposed RACT and BARCT emission limits. Evaluation centered on lean-burn compressor engines under 500 bhp, and rich-burn constant and cyclically loaded (rod pump) engines under 200 bhp. The results of the evaluation indicated that rich burn cyclically-loaded rod pump engines comprised 50 percent of the affected ICE population, though these ICEs accounted for only 5 percent of the uncontrolled gas-fired stationary ICE NO_x emissions. Recommended retrofit NO_x control strategies included: air/fuel ratio adjustment for rod pump ICEs, Non-selective catalytic reduction (NSCR) for rich-burn, constant load ICEs, and "low emission" combustion modifications for lean burn ICEs.

Development of Air Emission Standards for Stationary ICEs - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian stationary ICE power plants. Draft 1997 World Bank NO_x and particulate emission limits for stationary ICE power plants served as the basis for proposed MEM emission limits. A detailed review of ICE emissions data provided in PAMAs submitted to the MEM was performed to determine the level of effort that would be required by Peruvian industry to meet the proposed NO_x and particulate emission limits. The draft 1997 WB emission limits were revised to reflect reasonably achievable NO_x and particulate emission limits for ICEs currently in operation in Peru.

Air Toxics Testing of Natural Gas-Fired ICEs. Project manager for test plan/test program to measure volatile and semi-volatile organic air toxics compounds from fourteen gas-fired ICEs used in a variety of oil and gas production applications. Test data was utilized by oil and gas production facility owners throughout California to develop accurate ICE air toxics emission inventories.

AIR ENGINEERING/AIR TESTING PROJECT EXPERIENCE – GENERAL

Reverse Air Fabric Filter Retrofit Evaluation – Coal-Fired Boiler. Lead engineer for upgrade of reverse air fabric filters serving coal-fired industrial boilers. Fluorescent dye injected to pinpoint broken bags and damper leaks. Corrosion of pneumatic actuators serving reverse air valves and inadequate insulation identified as principal causes of degraded performance.

Pulse-Jet Fabric Filter Performance Evaluation – Gold Mine. Lead engineer on upgrade of pulse-jet fabric filter and associated exhaust ventilation system serving an ore-crushing facility at a gold mine. Fluorescent dye used to identify bag collar leaks, and modifications were made to pulse air cycle time and duration. This marginal source was in compliance at 20 percent of emission limit following completion of repair work.

Pulse-Jet Fabric Filter Retrofit - Gypsum Calciner. Lead engineer on upgrade of pulse-jet fabric filter controlling particulate emissions from a gypsum calciner. Recommendations included a modified bag clamping mechanism, modified hopper evacuation valve assembly, and changes to pulse air cycle time and pulse duration.

Wet Scrubber Retrofit – Plating Shop. Project engineer on retrofit evaluation of plating shop packed-bed wet scrubbers failing to meet performance guarantees during acceptance trials, due to excessive mist carryover. Recommendations included relocation of the mist eliminator (ME), substitution of the original chevron blade ME with a mesh pad ME, and use of higher density packing material to improve exhaust gas distribution. Wet scrubbers passed acceptance trials following completion of recommended modifications.

Electrostatic Precipitator (ESP) Retrofit Evaluation – MSW Boiler. Lead engineer for retrofit evaluation of single field ESP on a municipal solid waste (MSW) boiler. Recommendations included addition of automated power controller, inlet duct turning vanes, and improved collecting plate rapping system.

ESP Electric Coil Rapper Vibration Analysis Testing - Coal-Fired Boiler. Lead engineer for evaluation of ESP rapper effectiveness test program on three field ESP equipped with "magnetically induced gravity return" (MIGR) rappers. Accelerometers were placed in a grid pattern on ESP collecting plates to determine maximum instantaneous plate acceleration at a variety of rapper power setpoints. Testing showed that the rappers met performance specification requirements.

Aluminum Remelt Furnace Particulate Emissions Testing. Project manager and lead engineer for high temperature (1,600 °F) particulate sampling of a natural gas-fired remelt furnace at a major aluminum rolling mill. Objectives of test program were to: 1) determine if condensable particulate was present in stack gases, and 2) to validate the accuracy of the in-stack continuous opacity monitor (COM). Designed and constructed a customized high temperature (inconel) PM_{10}/Mtd 17 sampling assembly for test program. An onsite natural gas-fired boiler was also tested to provide comparative data for the condensable particulate portion of the test program. Test results showed that no significant levels of condensable particulate in the remelt furnace exhaust gas, and indicated that the remelt furnace and boiler had similar particulate emission rates. Test results also showed that the COM was accurate.

Aluminum Remelt Furnace CO and NO_x Testing. Project manager and lead engineer for continuous week-long testing of CO and NO_x emissions from aluminum remelt furnace. Objective of test program was to characterize CO and NO_x emissions from representative remelt furnace for use in the facility's criteria pollution emissions inventory. A TECO Model 48 CO analyzer and a TECO Model 10 NO_x analyzer were utilized during the test program to provide $\pm$1 ppm measurement accuracy, and all test data was recorded by an automated data acquisition system.

PETROLEUM REFINERY AIR ENGINEERING/TESTING EXPERIENCE

Big West Refinery Expansion EIS. Lead engineer on comparative cost analysis of proposed wet cooling tower and fin-fan air cooler for process cooling water for the proposed clean fuels expansion project at the Big West Refinery in Bakersfield, California. Selection of the fin-fin air-cooler would eliminate all consumptive water use and wastewater disposal associated with the cooling tower. Air emissions of VOC and PM_{10} would be reduced with the fin-fan air-cooler even though power demand of the air-cooler is incrementally higher than that of the cooling tower. Fin-fan air-coolers with approach temperatures of 10 °F and 20 °F were evaluated. The annualized cost of the fin-fin air-cooler with a 20 °F approach temperature is essentially the same as that of the cooling tower when the cost of all ancillary cooling tower systems are considered.

Criteria and Air Toxic Pollutant Emissions Inventory for Proposed Refinery Modifications. Project manager and technical lead for development of baseline and future refinery air emissions inventories for process modifications required to produce oxygenated gasoline and desulfurized diesel fuel at a California refinery. State of the art criteria and air toxic pollutant emissions inventories for refinery point, fugitive and mobile sources were developed. Point source emissions estimates were generated using onsite criteria pollutant test data, onsite air toxics test data, and the latest air toxics emission factors from the statewide refinery air toxics inventory database. The fugitive volatile organic compound (VOC) emissions inventories were developed using the refinery's most recent inspection and maintenance (I&M) monitoring program test data to develop site-specific component VOC emission rates. These VOC emission rates were combined with speciated air toxics test results for the principal refinery process streams to produce fugitive VOC air toxics emission rates. The environmental impact report (EIR) that utilized this emission inventory data was the first refinery "Clean Fuels" EIR approved in California.

Development of Air Emission Standards for Petroleum Refinery Equipment - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian petroleum refineries. The sources included in the scope of this project included: 1) SO_2 and NO_x refinery heaters and boilers, 2) desulfurization of crude oil, particulate and SO_2 controls for fluid catalytic cracking units (FCCU), 3) VOC and CO emissions from flares, 4) vapor recovery systems for marine unloading, truck loading, and crude oil/refined products storage tanks, and 5) VOC emissions from process fugitive sources such as pressure relief valves, pumps, compressors and flanges. Proposed emission limits were developed for new and existing refineries based on a thorough evaluation of the available air emission control technologies for the affected refinery sources. Leading vendors of refinery control technology, such as John Zink and Exxon Research, provided estimates of retrofit costs for the largest Peruvian refinery, La Pampilla, located in Lima. Meetings were held in Lima with refinery operators and MEM staff to discuss the proposed emission limits and incorporate mutually agreed upon revisions to the proposed limits for existing Peruvian refineries.

Air Toxic Pollutant Emissions Inventory for Existing Refinery. Project manager and technical lead for air toxic pollutant emissions inventory at major California refinery. Emission factors were developed for refinery heaters, boilers, flares, sulfur recovery units, coker deheading, IC engines, storage tanks, process fugitives, and catalyst regeneration units. Onsite source test results were utilized to characterize emissions from refinery combustion devices. Where representative source test results were not available, AP-42 VOC emission factors were combined with available VOC air toxics speciation profiles to estimate VOC air toxic emission rates. A risk assessment based on this emissions inventory indicated a relatively low health risk associated with refinery operations. Benzene, 1,3-butadiene and PAHs were the principal health risk related pollutants emitted.

Air Toxics Testing of Refinery Combustion Sources. Project manager for comprehensive air toxics testing program at a major California refinery. Metals, Cr^{+6}, PAHs, H_2S and speciated VOC emissions were measured from refinery combustion sources. High temperature Cr^{+6} stack testing using the EPA Cr^{+6} test method was performed for the first time in California during this test program. Representatives from the California Air Resources Board source test team performed simultaneous testing using ARB Method 425 (Cr^{+6}) to compare the results of EPA and ARB Cr^{+6} test methodologies. The ARB approved the test results generated using the high temperature EPA Cr^{+6} test method.

Air Toxics Testing of Refinery Fugitive Sources. Project manager for test program to characterize air toxic fugitive VOC emissions from fifteen distinct process units at major California refinery. Gas, light liquid, and heavy liquid process streams were sampled. BTXE, 1,3-butadiene and propylene concentrations were quantified in gas samples, while BTXE, cresol and phenol concentrations were measured in liquid samples. Test results were combined with AP-42 fugitive VOC emission factors for valves, fittings, compressors, pumps and PRVs to calculate fugitive air toxics VOC emission rates.

OIL AND GAS PRODUCTION AIR ENGINEERING/TESTING EXPERIENCE

Air Toxics Testing of Oil and Gas Production Sources. Project manager and lead engineer for test plan/test program to determine VOC removal efficiency of packed tower scrubber controlling sulfur dioxide emissions from a crude oil-fired steam generator. Ratfisch 55 VOC analyzers were used to measure the packed tower scrubber VOC removal efficiency. Tedlar bag samples were collected simultaneously to correlate BTX removal efficiency to VOC removal efficiency. This test was one of hundreds of air toxics tests performed during this test program for oil and gas production facilities from 1990 to 1992. The majority of the volatile air toxics analyses were performed at in-house laboratory. Project staff developed thorough familiarity with the applications and limitations of GC/MS, GC/PID, GC/FID, GC/ECD and GC/FPD. Tedlar bags, canisters, sorbent tubes and impingers were used during sampling, along with isokinetic tests methods for multiple metals and PAHs.

Air Toxics Testing of Glycol Reboiler – Gas Processing Plant. Project manager for test program to determine emissions of BTXE from glycol reboiler vent at gas processing facility handling 12 MM/cfd of produced gas. Developed innovative test methods to accurately quantify BTXE emissions in reboiler vent gas.
Air Toxics Emissions Inventory Plan. Lead engineer for the development of generic air toxics emission estimating techniques (EETs) for oil and gas production equipment. This project was performed for the Western States Petroleum Association in response to the requirements of the California Air Toxics "Hot Spots" Act. EETs were developed for all point and fugitive oil and gas production sources of air toxics, and the specific air toxics associated with each source were identified. A pooled source emission test methodology was also developed to moderate the cost of source testing required by the Act.

Fugitive NMHC Emissions from TEOR Production Field. Project manager for the quantification of fugitive Nonmethane hydrocarbon (NMHC) emissions from a thermally enhanced oil recovery (TEOR) oil production field in Kern County, CA. This program included direct measurement of NMHC concentrations in storage tank vapor headspace and the modification of available NMHC emission factors for NMHC-emitting devices in TEOR produced gas service, such as wellheads, vapor trunklines, heat exchangers, and compressors. Modification of the existing NMHC emission factors was necessary due to the high concentration of CO_2 and water vapor in TEOR produced gases.

Fugitive Air Emissions Testing of Oil and Gas Production Fields. Project manager for test plan/test program to determine VOC and air toxics emissions from oil storage tanks, wastewater storage tanks and produced gas lines. Test results were utilized to develop comprehensive air toxics emissions inventories for oil and gas production companies participating in the test program.

Oil and Gas Production Field – Air Emissions Inventory and Air Modeling. Project manager for oil and gas production field risk assessment. Project included review and revision of the existing air toxics emission inventory, air dispersion modeling, and calculation of the acute health risk, chronic non-carcinogenic risk and carcinogenic risk of facility operations. Results indicated that fugitive H_2S emissions from facility operations posed a potential health risk at the facility fenceline.

TITLE V PERMIT APPLICATION/MONITORING PLAN EXPERIENCE

Title V Permit Application – San Diego County Industrial Facility. Project engineer tasked with preparing streamlined Title V operating permit for U.S. Navy facilities in San Diego. Principal emission units included chrome plating, lead furnaces, IC engines, solvent usage, aerospace coating and marine coating operations. For each device category in use at the facility, federal MACT requirements were integrated with District requirements in user friendly tables that summarized permit conditions and compliance status.

Title V Permit Application Device Templates - Oil and Gas Production Industry. Project manager and lead engineer to prepare Title V permit application “templates” for the Western States Petroleum Association (WSPA). The template approach was chosen by WSPA to minimize the administrative burden associated with listing permit conditions for a large number of similar devices located at the same oil and gas production facility. Templates are being developed for device types common to oil and gas production operations. Device types include: boilers, steam generators, process heaters, gas turbines, IC engines, fixed-roof storage tanks, fugitive components, flares, and cooling towers. These templates will serve as the core of Title V permit applications prepared for oil and gas production operations in California.

Title V Permit Application - Aluminum Rolling Mill. Project manager and lead engineer for Title V permit application prepared for largest aluminum rolling mill in the western U.S. Responsible for the overall direction of the permit application project, development of a monitoring plan for significant emission units, and development of a hazardous air pollutant (HAP) emissions inventory. The project involved extensive onsite data gathering, frequent interaction with the plant's technical and operating staff, and coordination with legal counsel and subcontractors. The permit application was completed on time and in budget.

Title V Model Permit - Oil and Gas Production Industry. Project manager and lead engineer for the comparative analysis of regional and federal requirements affecting oil and gas production industry sources located in the San Joaquin Valley. Sources included gas turbines, IC engines, steam generators, storage tanks, and process fugitives. From this analysis, a model applicable requirements table was developed for a sample device type (storage tanks) that covered the entire population of storage tanks operated by the industry. The U.S. EPA has tentatively approved this model permit approach, and work is ongoing to develop comprehensive applicable requirements tables for each major category of sources operated by the oil and gas industry in the San Joaquin Valley.

Title V Enhanced Monitoring Evaluation of Oil and Gas Production Sources. Lead engineer to identify differences in proposed EPA Title V enhanced monitoring protocols and the current monitoring requirements for oil and gas production sources in the San Joaquin Valley. The device types evaluated included: steam generators, stationary ICEs, gas turbines, fugitives, fixed roof storage tanks, and thermally enhanced oil recovery (TEOR) well vents. Principal areas of difference included: more stringent Title V O&M requirements for parameter monitors (such as temperature, fuel flow, and O_2), and more extensive Title V recordkeeping requirements.

RACT/BARCT/BACT EVALUATIONS

RACT/BARCT Reverse Jet Scrubber/Fiberbed Mist Eliminator Retrofit Evaluation. Project manager and lead engineer on project to address the inability of existing wet electrostatic precipitators (ESPs) and atomized mist scrubbers to adequately remove low concentration submicron particulate from high volume recovery boiler exhaust gas at the Alaska Pulp Corporation mill in Sitka, AK. The project involved thorough on-site inspections of existing control equipment, detailed review of maintenance and performance records, and a detailed evaluation of potential replacement technologies. These technologies included a wide variety of scrubbing technologies where manufacturers claimed high removal efficiencies on submicron particulate in high humidity exhaust gas. Packed tower scrubbers, venturi scrubbers, reverse jet scrubbers, fiberbed mist eliminators and wet ESPs were evaluated. Final recommendations included replacement of atomized mist scrubber with reverse jet scrubber and upgrading of the existing wet ESPs. The paper describing this project was published in the May 1992 TAPPI Journal.

Aluminum Smelter RACT Evaluation - Prebake. Project manager and technical lead for CO and PM_{10} RACT evaluation for prebake facility. Retrofit control options for CO emissions from the anode bake furnace, potline dry scrubbers and the potroom roof vents were evaluated. PM_{10} emissions from the coke kiln, potline dry scrubbers, potroom roof vents, and miscellaneous potroom fugitive sources were addressed. Four CO control technologies were identified as technologically feasible for potline CO emissions: potline current efficiency improvement through the addition of underhung busswork and automated puncher/feeders, catalytic incineration, recuperative incineration and regenerative incineration. Current efficiency improvement was identified as probable CO RACT if onsite test program demonstrated the effectiveness of this approach. Five PM_{10} control technologies were identified as technologically feasible: increased potline hooding efficiency through redesign of shields, the addition of a dense-phase conveying system, increased potline air evacuation rate, wet scrubbing of roof vent emissions, and fabric filter control of roof vent emissions.

RACT/BACT Testing/Evaluation of PM_{10} Mist Eliminators on Five-Stand Cold Mill. Project manager and lead engineer for fiberbed mist eliminator and mesh pad mist eliminator comparative pilot test program on mixed phase aerosol (PM_{10})/gaseous hydrocarbon emissions from aluminum high speed cold rolling mill. Utilized modified EPA Method 5 sampling train with portion of sample gas diverted (after particulate filter) to Ratfisch 55 VOC analyzer. This was done to permit simultaneous quantification of aerosol and gaseous hydrocarbon emissions in the exhaust gas. The mesh pad mist eliminator demonstrated good control of PM_{10} emissions, though test results indicated that the majority of captured PM_{10} evaporated in the mesh pad and was emitted as VOC.

Aluminum Remelt Furnace/Rolling Mill RACT Evaluations. Lead engineer for comprehensive CO and PM_{10} RACT evaluation for the largest aluminum sheet and plate rolling mill in western U.S. Significant sources of CO emissions from the facility included the remelt furnaces and the coater line. The potential CO RACT options for the remelt furnaces included: enhanced maintenance practices, preheating combustion air, installation of fully automated combustion controls, and energy efficiency modifications.

BARCT Low NO_x Burner Conversion – Industrial Boilers. Lead engineer for evaluation of low NO_x burner options for natural gas-fired industrial boilers. Also evaluated methanol and propane as stand-by fuels to replace existing diesel stand-by fuel system. Evaluated replacement of steam boilers with gas turbine co-generation system.

BACT Packed Tower Scrubber/Mist Eliminator Performance Evaluations. Project manager and lead engineer for Navy-wide plating shop air pollution control technology evaluation and emissions testing program. Mist eliminators and packed tower scrubbers controlling metal plating processes, which included hard chrome, nickel, copper, cadmium and precious metals plating, were extensively tested at three Navy plating shops.

Chemical cleaning and stripping tanks, including hydrochloric acid, sulfuric acid, chromic acid and caustic, were also tested. The final product of this program was a military design specification for plating and chemical cleaning shop air pollution control systems. The hydrochloric acid mist sampling procedure developed during this program received a protected patent.

BACT Packed Tower Scrubber/UV Oxidation System Pilot Test Program. Technical advisor for pilot test program of packed tower scrubber/ultraviolet (UV) light VOC oxidation system controlling VOC emissions from microchip manufacturing facility in Los Angeles. The testing was sponsored in part by the SCAQMD's Innovative Technology Demonstration Program, to demonstrate this innovative control technology as BACT for microchip manufacturing operations. The target compounds were acetone, methylethylketone (MEK) and 1,1,1-trichloroethane, and compound concentrations ranged from 10-100 ppmv. The single stage packed tower scrubber consistently achieved greater than 90% removal efficiency on the target compounds. The residence time required in the UV oxidation system for effective oxidation of the target compounds proved significantly longer than the residence time predicted by the manufacturer.

BACT Pilot Testing of Venturi Scrubber on Gas/Aerosol VOC Emission Source. Technical advisor for project to evaluate venturi scrubber as BACT for mixed phase aerosol/gaseous hydrocarbon emissions from deep fat fryer. Venturi scrubber demonstrated high removal efficiency on aerosol, low efficiency on VOC emissions. A number of VOC tests indicated negative removal efficiency. This anomaly was traced to a high hydrocarbon concentration in the scrubber water. The pilot unit had been shipped directly to the jobsite from another test location by the manufacturer without any cleaning or inspection of the pilot unit.

Pulp Mill Recovery Boiler BACT Evaluation. Lead engineer for BACT analysis for control of SO_2, NO_x, CO, TNMHC, TRS and particulate emissions from the proposed addition of a new recovery furnace at a kraft pulp mill in Washington. A "top down" approach was used to evaluate potential control technologies for each of the pollutants considered in the evaluation.

Air Pollution Control Equipment Design Specification Development. Lead engineer for the development of detailed Navy design specifications for wet scrubbers and mist eliminators. Design specifications were based on field performance evaluations conducted at the Long Beach Naval Shipyard, Norfolk Naval Shipyard, and Jacksonville Naval Air Station. This work was performed for the U.S. Navy to provide generic design specifications to assist naval facility engineering divisions with air pollution control equipment selection. Also served as project engineer for the development of Navy design specifications for ESPs and fabric filters.

CONTINUOUS EMISSION MONITOR (CEM) PROJECT EXPERIENCE

Process Heater CO and NO_x CEM Relative Accuracy Testing. Project manager and lead engineer for process heater CO and NO_x analyzer relative accuracy test program at petrochemical manufacturing facility. Objective of test program was to demonstrate that performance of onsite CO and NO_x CEMs was in compliance with U.S. EPA "Boiler and Industrial Furnace" hazardous waste co-firing regulations. A TECO Model 48 CO analyzer and a TECO Model 10 NO_x analyzer were utilized during the test program to provide $\pm$1 ppm measurement accuracy, and all test data was recorded by an automated data acquisition system. One of the two process heater CEM systems tested failed the initial test due to leaks in the gas conditioning system. Troubleshooting was performed using O_2 analyzers, and the leaking component was identified and replaced. This CEM system met all CEM relative accuracy requirements during the subsequent retest.

Performance Audit of NO_x and SO_2 CEMs at Coal-Fired Power Plant. Lead engineer on system audit and challenge gas performance audit of NO_x and SO_2 CEMs at a coal-fired power plant in southern Nevada. Dynamic and instrument calibration checks were performed on the CEMs. A detailed visual inspection of the CEM system, from the gas sampling probes at the stack to the CEM sample gas outlet tubing in the CEM trailer, was also conducted. The CEMs passed the dynamic and instrument calibration requirements specified in EPA's Performance Specification Test - 2 (NO_x and SO_2) alternative relative accuracy requirements.

LATIN AMERICA ENVIRONMENTAL PROJECT EXPERIENCE

Assessment of operational deficiencies of Camisa pipeline – Peru. Project leader of multi-year assessment of root causes of ruptures on Camisea 14-inch natural gas liquids pipeline for non-profit client. Determined that primary causes of hurried construction in difficult and unstable terrain, unstable right-of-way in the jungle sector due to inadequate erosion control practices, and inadequate pipe wall thickness to withstand external lateral forces. Two assessments were developed during the course of the project documenting deficiencies and recommending remedial actions.

Evaluation of U.S.-Mexico Border Region Copper Smelter Compliance with Treaty Obligations – Mexico. Project manager and lead engineer to evaluate compliance of U.S. and Mexican border region copper smelters with the SO_2 monitoring, recordkeeping and reporting requirements in Annex IV [Copper Smelters] of the La Paz Environmental Treaty. Identified potential problems with current ambient and stack monitoring practices that could result in underestimating the impact of SO_2 emissions from some of these copper smelters. Identified additional source types, including hazardous waste incinerators and power plants, that should be considered for inclusion in the La Paz Treaty process.

Development of Air Emission Limits for ICE Cogeneration Plant - Panamá. Lead engineer assisting U.S. cogeneration plant developer to permit an ICE cogeneration plant at a hotel/casino complex in Panama. Recommended the use of modified draft World Bank NO_x and PM limits for ICE power plants. The modification consisted of adding a thermal efficiency factor adjustment to the draft World Bank NO_x and PM limits. These proposed ICE emission limits are currently being reviewed by Panamanian environmental authorities.

Mercury Emissions Inventory for Stationary Sources in Northern Mexico. Project manager and lead engineer to estimate mercury emissions from stationary sources in Northern Mexico. Major potential sources of mercury emissions include solid- and liquid-fueled power plants, cement kilns co-firing hazardous waste, and non-ferrous metal smelters. Emission estimates were provided for approximately eighty of these sources located in Northern Mexico. Coordinated efforts of two Mexican subcontractors, located in Mexico City and Hermosillo, to obtain process throughput data for each source included in the inventory.

Translation of U.S. EPA Scrap Tire Combustion Emissions Estimation Document – Mexico. Evaluated the Translated a U.S. EPA scrap tire combustion emissions estimation document from English to Spanish for use by Latin American environmental professionals.

Environmental Audit of Aluminum Production Facilities – Venezuela. Evaluated the capabilities of existing air, wastewater and solid/hazardous waste control systems used by the aluminum industry in eastern Venezuela. This industry will be privatized in the near future. Estimated the cost to bring these control systems into compliance with air, wastewater and solid/hazardous waste standards recently promulgated in Venezuela. Also served as technical translator for team of U.S. environmental engineers involved in the due diligence assessment.

Assessment of Environmental Improvement Projects – Chile and Peru. Evaluated potential air, water, soil remediation and waste recycling projects in Lima, Peru and Santiago, Chile for feasibility study funding by the U.S. Trade and Development Agency. Project required onsite interaction with in-country decisionmakers (in Spanish). Projects recommended for feasibility study funding included: 1) an air quality technical support project for the Santiago, Chile region, and 2) soil remediation/metals recovery projects at two copper mine/smelter sites in Peru.

Air Pollution Control Training Course – Mexico. Conducted two-day Spanish language air quality training course for environmental managers of assembly plants in Mexicali, Mexico. Spanish-language course manual prepared by Powers Engineering. Practical laboratory included training in use of combustion gas analyzer, flame ionization detector (FID), photoionization detector (PID), and occupational sampling.

Stationary Source Emissions Inventory – Mexico. Developed a comprehensive air emissions inventory for stationary sources in Nogales, Sonora. This project requires frequent interaction with Mexican state and federal environmental authorities. The principal Powers Engineering subcontractor on this project is a Mexican firm located in Hermosillo, Sonora.

VOC Measurement Program – Mexico. Performed a comprehensive volatile organic compound (VOC) measurements program at a health products fabrication plant in Mexicali, Mexico. An FID and PID were used to quantify VOCs from five processes at the facility. Occupational exposures were also measured. Worker exposure levels were above allowable levels at several points in the main assembly area.

Fluent in Spanish. Studied at the Universidad de Michoacán in Morelia, Mexico, 1993, and at the Colegio de España in Salamanca, Spain, 1987-88. Have lectured (in Spanish) on air monitoring and control equipment at the Instituto Tecnológico de Tijuana. Maintain contact with Comisión Federal de Electricidad engineers responsible for operation of wind and geothermal power plants in Mexico, and am comfortable operating in the Mexican business environment.

PUBLICATIONS

Bill Powers, "*More Distributed Solar Means Fewer New Combustion Turbines*," Natural Gas & Electricity Journal, Vol. 29, Number 2, September 2012, pp. 17-20.

Bill Powers, "*Federal Government Betting on Wrong Solar Horse*," Natural Gas & Electricity Journal, Vol. 27, Number 5, December 2010,

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Bill Powers, "*Environmental Problem Solving Itself Rapidly Through Lower Gas Costs*," Natural Gas & Electricity Journal, Vol. 26, Number 4, November 2009, pp. 9-14.

Bill Powers, "*PV Pulling Ahead, but Why Pay Transmission Costs?*" Natural Gas & Electricity Journal, Vol. 26, Number 3, October 2009, pp. 19-22.

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Bill Powers, "*CEC Cancels Gas-Fed Peaker, Suggesting Rooftop Photovoltaic Equally Cost-Effective*," Natural Gas & Electricity Journal, Vol. 26, Number 1, August 2009, pp. 8-13.

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Bill Powers, "*Energy, the Environment, and the California – Baja California Border Region*," Electricity Journal, Vol. 18, Issue 6, July 2005, pp. 77-84.

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P. Pai, D. Niemi, W.E. Powers, *"A North American Anthropogenic Inventory of Mercury Emissions,"* presented at Air & Waste Management Association Annual Conference in Salt Lake City, UT, June 2000.

P.J. Blau and W.E. Powers, *"Control of Hazardous Air Emissions from Secondary Aluminum Casting Furnace Operations Through a Combination of: Upstream Pollution Prevention Measures, Process Modifications and End-of-Pipe Controls,"* presented at 1997 AWMA/EPA Emerging Solutions to VOC & Air Toxics Control Conference, San Diego, CA, February 1997.

W.E. Powers, et. al., *"Hazardous Air Pollutant Emission Inventory for Stationary Sources in Nogales, Sonora, Mexico ,"* presented at 1995 AWMA/EPA Emissions Inventory Specialty Conference, RTP, NC, October 1995.

W.E. Powers, *"Develop of a Parametric Emissions Monitoring System to Predict NO_x Emissions from Industrial Gas Turbines,"* presented at 1995 AWMA Golden West Chapter Air Pollution Control Specialty Conference, Ventura, California, March 1995.

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S. S. Parmar, M. Short, W. E. Powers, *"Determination of Total Gaseous Hydrocarbon Emissions from an Aluminum Rolling Mill Using Methods 25, 25A, and an Oxidation Technique,"* presented at U.S. EPA Measurement of Toxic and Related Air Pollutants Conference, May 1992.

N. Meeks, W. E. Powers, *"Air Toxics Emissions from Gas-Fired Internal Combustion Engines,"* presented at AIChE Summer Meeting, August 1990.

W. E. Powers, *"Air Pollution Control of Plating Shop Processes,"* presented at 7th AES/EPA Conference on Pollution Control in the Electroplating Industry, January 1986. Published in *Plating and Surface Finishing* magazine, July 1986.

H. M. Davenport, W. E. Powers, *"Affect of Low Cost Modifications on the Performance of an Undersized Electrostatic Precipitator,"* presented at 79th Air Pollution Control Association Conference, June 1986.

AWARDS

Engineer of the Year, 1991 – ENSR Consulting and Engineering, Camarillo
Engineer of the Year, 1986 – Naval Energy and Environmental Support Activity, Port Hueneme
Productivity Excellence Award, 1985 – U. S. Department of Defense

PATENTS

Sedimentation Chamber for Sizing Acid Mist, Navy Case Number 70094

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

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

Exhibit 5
Synapse Report

Memorandum

TO: EARTHJUSTICE, ENVIRONMENTAL LAW & POLICY CENTER, AND SIERRA CLUB

FROM: LUCY METZ AND DEVI GLICK

DATE: JANUARY 21, 2026

RE: COST OF CONTINUED OPERATION OF CULLEY UNIT 2 AND SCHAHFER UNITS 17–18 UNDER FEDERAL POWER ACT ORDERS

Executive Summary

Three coal units in Indiana—Culley 2, Schahfer 17, and Schahfer 18—were scheduled to retire at the end of 2025. However, the U.S. Department of Energy (DOE) issued two orders requiring the units to continue operating beyond their planned retirement dates.[1] This is concerning based on both cost and environmental impact.

We find that continued operation of the three units under economic commitment practices will result in net-costs[2] to the plant owners of $229,000 per day or $20.6 million over the initial 90-day order period. This includes $1.9 million for Culley 2, $9.8 million for Schahfer 17, and $8.9 million for Schahfer 18. If DOE additionally requires the three units to operate under a must-run commitment status (i.e., to remain online at a minimum dispatch level regardless of whether it is economic to do so), net losses would be even higher at $250,000 per day, or $22.5 million over the initial order period. Under either economic or must-run dispatch, costs will likely be passed on to ratepayers in the region—not taxpayers at large. We calculate these net losses based on the short-term gross costs associated with operating the coal units (fuel, variable operations and maintenance (VOM), and fixed operations and maintenance (FOM) costs) and the energy market revenues the units earn. These calculations assume that Schahfer 18 will be available over the 90-day period, although NIPSCO has stated Schahfer 18 will need repairs that will take longer than the initial 90-day period.

We assume that the units have no capacity value over the order period, based on the timing of MISO capacity auctions and the requirements of the DOE order, as we describe in more detail below.

The estimates above include short-term costs only. If DOE extends the order long-term, we estimate the coal units would require an additional $33.7 million per year in capital expenditures to replace

[1] U.S. Department of Energy. 2025. "2025 DOE 202(c) Orders." Available at: https://www.energy.gov/ceser/2025-doe-202c-orders.

[2] Net costs refer to gross costs net of MISO market energy revenues.

equipment as it wears out and install environmental controls to maintain compliance with environmental regulations.

Introduction

The Trump Administration's DOE has used authority under Section 202(c) of the Federal Power Act to issue several orders requiring power plants to remain online past their scheduled retirement dates. DOE first took this action with the J.H. Campbell Power Plant, a 1.5 GW coal plant in Michigan, on May 23, 2025. The initial order extended for 90 days. Since then, DOE has continued to issue orders extending the requirement for Campbell; the most recent order goes through mid-February 2026.[3] DOE issued similar orders for Eddystone Generating Station, an oil- and gas-fired power plant in Pennsylvania; Centralia Generating Station, a coal-fired plant in Washington; and Craig Station, a coal-fired plant in Colorado.[4]

Additionally, on December 23, 2025, DOE issued two Section 202(c) orders covering three coal units in Indiana scheduled to retire at the end of 2025: Culley 2, Schahfer 17, and Schahfer 18 (Table 1).[5] In this memo, we estimate the costs of a DOE order forcing Culley 2 and Schahfer 17–18 to remain online and generating electricity after December 31, 2025.

Table 1. Coal units scheduled for retirement

Unit	Location	Nameplate capacity (MW)	Online year	Scheduled retirement date	Owner
Culley 2	Warrick County, IN	103.7	1966	End of year 2025	CenterPoint
Schahfer 17	Jasper County, IN	423.5	1983	End of year 2025	NIPSCO
Schahfer 18	Jasper County, IN	423.5	1986	End of year 2025	NIPSCO

Source: U.S. Energy Information Administration (EIA) Form 860, 2024 release. NIPSCO is the Northern Indiana Public Service Company.

Methodology

We calculate the incremental cost of operating the units over the initial 90 days of the order (i.e., the net loss incurred by the unit owners relative to alternative resources), based on the coal units' short-term costs and energy revenues. Short-term costs include fuel, VOM, and FOM. We assume that in the short term, unit owners will not have time to make additional capital investments in the units. For any

[3] U.S. Department of Energy. 2025. "2025 DOE 202(c) Orders." Available at: https://www.energy.gov/ceser/2025-doe-202c-orders.
[4] Ibid.
[5] U.S. Department of Energy. 2025. "Federal Power Act Section 202(c): Culley Order No. 202-25-13." Available at: https://www.energy.gov/ceser/federal-power-act-section-202c-culley-order-no-202-25-13; U.S. Department of Energy. 2025. "Schahfer Order No. 202-25-12." Available at: https://www.energy.gov/ceser/federal-power-act-section-202c-schahfer-order-no-202-25-12.

units that were not operable as of the start date of the order, unit owners will likely not be able to complete the capital investments necessary to make the unit operable. However, for the sake of this analysis, we assume that each unit is operable for the 90-day period.

We also calculate the energy market revenue that the units generate over the order period. We assume that the units do not have any avoided capacity value, as explained below. We then calculate incremental costs by taking the difference between the gross short-term costs and the energy market revenue.

Finally, we calculate long-term costs if DOE orders the units to remain online for a year or more, including sustaining capital expenditures necessary to replace equipment at end-of-life and maintain environmental compliance.

Short-Term Gross Costs

To calculate short-term gross costs, we first estimate the capacity factors of the units using historical hourly generation data published by the U.S. Environmental Protection Agency.[6] We include two scenarios for capacity factors: one representing economic commitment (Table 3) and the other representing must-run commitment (Table 4 and Table 5):

- In the economic commitment scenario, we assume that the capacity factor of each unit during the term of the DOE order will be consistent with its average capacity factor over the past six years (2020–2025).
- In the must-run scenario, we re-calculate the capacity factor assuming that the units are committed in all hours. In hours when a unit was historically offline, we instead assume that generation never falls below the minimum dispatch level shown in Table 2, except for hours when the plant is in planned or unplanned outage.

We use outage rates, as shown in Table 2, from the North American Reliability Council's (NERC) Generating Availability Data System for coal units of a similar size to Culley 2 and Schahfer 17–18.[7] We then translate both sets of capacity factors into monthly quantities of coal consumption using heat rates from Horizon's National Database.[8] In Table 4, we apply outages evenly throughout the year for simplicity; in reality there would likely be several long planned maintenance outages in the spring and

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[6] U.S. Environmental Protection Agency Clean Air Markets Program Data (CAMPD). 2025. Available at: https://campd.epa.gov/data/custom-data-download.

[7] North American Reliability Corporation (NERC). 2025. "Generating Unit Statistical Brochure 4 2020–2024 – All Units Reporting." Available at: https://www.nerc.com/programs/reliability-assessment--performance-analysis/generating-availability-data-system/gads-conventional/generating-unit-statistical-brochures.

[8] More information on Horizon Energy's National Database is available at https://www.horizons-energy.com/encompass/. Data in this dataset is from various sources, including: (1) the U.S. Energy Information Administration, (2) U.S. Environmental Protection Agency, (3) North American Electric Reliability Corporation, (4) Federal Energy Regulatory Commission (FERC), (5) ISO New England, and (6) various trade press announcements.

fall, and then shorter outages scattered randomly throughout the year. In Table 5, we do not apply any outages.

We project coal prices during the order period based on historical coal price data for each unit from the U.S. Energy Information Administration[9] and a year-on-year price trajectory for future years from Horizon's National Database. Because there is no consistent monthly pattern in the historical coal prices, we project fuel prices on an annual basis. We calculate total fuel costs by multiplying monthly coal consumption by fuel price. Finally, we estimate VOM and FOM using unit-specific values from the Horizons National Database.

Table 2. Coal unit parameters

Quantity	Culley 2	Schahfer 17	Schahfer 18
Minimum dispatch (MW)*	50	110	110
Heat rate (MMBtu/MWh)	12	11	11
Percent of hours in planned or unplanned outage	17%	18%	18%
Variable operations and maintenance (2025$/MWh)	$11	$8	$8
Fixed operations and maintenance (2025$/kW-year)	$66	$56	$56
Coal price in 2026 (2025$/MMBtu)	$2.95	$4.55	$4.55

Sources: Horizon's National Database; EIA Form 923, 2020–2024 releases and 2025 release through September 2025; and North American Reliability Corporation (NERC). 2025. "Generating Unit Statistical Brochure 4 2020–2024 – All Units Reporting." Available at: https://www.nerc.com/programs/reliability-assessment--performance-analysis/generating-availability-data-system/gads-conventional/generating-unit-statistical-brochures*. To convert FOM costs from $/kW-year to $/MWh, multiply the value shown in the table by 1,000 kW/MW, divide by 8,760 hours/year, and then divide by the capacity factor.*
**Note that the minimum dispatch level for Schahfer 17 and 18 differs based on source. We relied on EIA numbers, but looking at hourly CAMPD data, the minimum level looks closer to 160 MW.*

Energy Market Revenue

The coal units receive MISO energy market revenue during hours when they are online. We use market revenue to represent the avoided energy cost of the units—the costs that unit owners would have incurred to replace the energy from the units, if the units had been allowed to retire on schedule. To the extent that a utility would have otherwise relied on a resource that was less costly to operate than market energy, the reported savings would be even larger than what we estimate here. To estimate energy market revenue, we use around-the-clock energy market price projections from CenterPoint and

[9] EIA form 923, 2020–2024 releases and 2025 release through September 2025. Available at: https://www.eia.gov/electricity/data/eia923/.

NIPSCO's most recent integrated resource plans. The price is $43 per MWh (2025$) in 2026 for CenterPoint and $45 per MWh (2025$) for NIPSCO.[10,11]

We assume that the coal units do not have any capacity value, because the DOE orders require that the units "shall not be considered a capacity resource."[12] Additionally, the MISO capacity auction (Planning Resource Action or PRA) for the current planning year, which goes through May 31, 2026, occurred last spring.[13] The coal units were not bid in at this time because they were scheduled to retire. In general, resources that did not participate in the PRA can bid as replacement resources and receive zonal resource credits (ZRC) instead.[14] However, given that the DOE order says the coal units are not considered capacity resources, it seems unlikely they would have the opportunity to earn this revenue.

Short-Term Incremental Costs

We calculate the incremental cost of continued operation of the units by taking the difference between the short-term gross costs and the energy market revenues generated by each unit. The incremental cost represents the net loss that CenterPoint and NIPSCO will likely incur and pass on to their ratepayers because of the DOE order.

Long-Term Costs

In addition to any repairs needed in the near term to restore units to an operable condition, if DOE continues to order the units to operate long term, the units will require additional capital investments to replace equipment components that wear out and maintain compliance with environmental regulations. We estimate sustaining capital expenditures using a Sargent and Lundy survey of U.S. coal plant capital expenditures as a function of unit age.[15] There are no avoidable long-term costs associated with alternative resources.[16]

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[10] CenterPoint Energy. 2025. *2025 Integrated Resource Plan.* Available at: https://www.centerpointenergy.com/en-us/business/services/integrated-resource-plan?sa=in.

[11] NIPSCO. 2024. *Integrated Resource Plan.* Available at: https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/irp/nipsco_2024-irp.pdf.

[12] U.S. Department of Energy. 2025. "Federal Power Act Section 202(c): Culley Order No. 202-25-13." Available at: https://www.energy.gov/ceser/federal-power-act-section-202c-culley-order-no-202-25-13; U.S. Department of Energy. 2025. "Schahfer Order No. 202-25-12." Available at: https://www.energy.gov/ceser/federal-power-act-section-202c-schahfer-order-no-202-25-12.

[13] MISO Resource Adequacy Business Practices Manual, BPM-011-r32. Appendix K.

[14] MISO Resource Adequacy Business Practices Manual, BPM-011-r32. Section 6.4 Replacement Resources.

[15] Sargent & Lundy. 2018. *Generating Unit Annual Capital and Life Extension Costs Analysis: Final Report on Modeling Aging-Related Capital and O&M Costs.* Prepared for the U.S. Energy Information Administration. Available at: https://www.eia.gov/analysis/studies/powerplants/generationcost/pdf/full_report.pdf.

[16] There is no evidence that specific fixed or capital costs are being delayed or deferred at other resources as a result of the coal units being kept online.

Results

Short-Term Gross and Incremental Cost Results

The total gross cost to continue operating Culley 2 and Schahfer 17–18 for 90 days past December 23, 2025, is $512,000 per day, assuming economic commitment (Table 3). Over the 90-day initial order period, this adds up to a total gross cost of $46 million, including $4.2 million for Culley 2, $22.8 million for Schahfer 17, and $19.1 million for Schahfer 18. Table 3 shows the breakdown of these costs between fuel, VOM, and FOM.

Over the initial order period, the three units combined receive $25 million in energy market revenue, assuming economic commitment. Revenue is much lower than gross costs over this period, indicating that the unit owners incur net losses because of the DOE order. Continued operation of the plants causes a net loss of $229,000 per day, for a total of $20.6 million over the order period. This includes $1.9 million for Culley 2, $9.8 million for Schahfer 17, and $8.9 million for Schahfer 18.

Table 3. Cost to operate plants for the 90-day term of the December 2025 202(c) orders under economic commitment

Quantity	Culley 2	Schahfer 17	Schahfer 18	Total
Capacity Factor (%)	24%	33%	26%	—
Fuel costs (thousands 2025$)	$1,939	$14,586	$11,399	$27,924
VOM (thousands 2025$)	$581	$2,350	$1,837	$4,768
FOM (thousands 2025$)	$1,681	$5,841	$5,841	$13,363
Gross cost (thousands 2025$)	$4,200	$22,777	$19,077	$46,054
Energy market revenue (thousands 2025$)	($2,326)	($12,964)	($10,131)	($25,421)
Incremental (net) cost (thousands 2025$)	**$1,874**	**$9,814**	**$8,946**	**$20,633**
Gross cost per day (thousands 2025$/day)	**$47**	**$253**	**$212**	**$512**
Incremental (net) cost per day (thousands 2025$/day)	**$21**	**$109**	**$99**	**$229**

Notes: Gross costs are the sum of fuel costs, VOM, and FOM. Incremental costs are equal to gross costs minus energy market revenues.

If DOE additionally requires the three units to operate under a must-run commitment status, gross costs will be higher at $617,000 per day (Table 4). This results in a total gross cost of $56 million over the initial 90-day order period, including $6.6 million for Culley 2, $25.5 million for Schahfer 17, and $23.4 million for Schahfer 18. The higher costs are a result of the increased capacity factors in this scenario, which result in higher fuel and variable operations and maintenance costs. Net losses in this scenario are also higher at $250,000 per day, or $22.5 million over the entire study period. These results, shown in Table 4, assume average planned and unplanned maintenance outages. Table 5 shows must-run results assuming there are no planned or unplanned outages to book-end the results.

Table 4. Cost to operate plants for the 90-day term of the December 2025 202(c) orders under must-run commitment assuming maintenance and unplanned outages

Quantity	Culley 2	Schahfer 17	Schahfer 18	Total
Capacity Factor (%)	47%	38%	34%	–
Fuel costs (thousands 2025$)	$3,754	$16,960	$15,156	$35,869
VOM (thousands 2025$)	$1,124	$2,733	$2,442	$6,299
FOM (thousands 2025$)	$1,681	$5,841	$5,841	$13,363
Gross cost (thousands 2025$)	$6,558	$25,534	$23,440	$55,531
Energy market revenue (thousands 2025$)	($4,504)	($15,074)	($13,471)	($33,048)
Incremental (net) cost (thousands 2025$)	**$2,055**	**$10,460**	**$9,969**	**$22,484**
Gross cost per day (thousands 2025$/day)	**$73**	**$284**	**$260**	**$617**
Incremental (net) cost per day (thousands 2025$/day)	**$23**	**$116**	**$111**	**$250**

Table 5. Cost to operate plants for the 90-day term of the December 2025 202(c) orders under must-run commitment without maintenance and unplanned outages

Quantity	Culley 2	Schahfer 17	Schahfer 18	Total
Capacity Factor (%)	55%	43%	39%	–
Fuel costs (thousands 2025$)	$4,423	$19,089	$17,285	$40,797
VOM (thousands 2025$)	$1,324	$3,076	$2,785	$7,186
FOM (thousands 2025$)	$1,681	$5,841	$5,841	$13,363
Gross cost (thousands 2025$)	$7,428	$28,006	$25,912	$61,346
Energy market revenue (thousands 2025$)	($5,307)	($16,966)	($15,363)	($37,636)
Incremental (net) cost (thousands 2025$)	**$2,121**	**$11,040**	**$10,549**	**$23,710**
Gross cost per day (thousands 2025$/day)	**$83**	**$311**	**$288**	**$682**
Incremental (net) cost per day (thousands 2025$/day)	**$24**	**$123**	**$117**	**$263**

The Campbell coal plant, which has been operating under a Section 202(c) order since late May 2025, provides a point of comparison for these results. In a recent filing with the U.S. Securities and Exchange Commission, Consumers Energy, the owner of Campbell, reported incurring $164 million of gross costs to keep the plant online from late May through the end of September.[17] This is equivalent to $835 per

[17] Consumers Energy reported that it incurred a net loss of $53 million in the first order period, after applying $67 million in MISO revenues. For the portion of the second 202(c) order period through the end of September 2025, it incurred a net loss of $27 million after applying $17 million in revenue. This implies that total gross costs to operate the plant over both time periods was $164 million. See Consumers Energy Company Form 10-Q for the quarterly period ending September 30, 2025, filed with the U.S. Securities and Exchange Commission (SEC).

MW-day. Table 6 shows the gross cost results for Culley Unit 2 and Schahfer Units 17–18 converted to $/MW-day. Culley and Schahfer would have costs of $450–$598 per MW-day under economic commitment, which is 28–46 percent less than the cost at Campbell. Under must-run commitment (with outages), costs for Culley and Schahfer are in the range of $615–703 per MW-day, 16–26 percent less than the cost at Campbell. This suggests that the cost estimates presented here are conservative.

Table 6. Cost results for Culley and Schahfer converted to $/MW-day

Quantity	Culley 2	Schahfer 17	Schahfer 18
Gross costs under economic commitment (2025$/MW-day)	$450	$598	$501
Gross costs under must run commitment (with outages) (2025$/MW-day)	$703	$670	$615

There are several reasons that the cost to operate a unit beyond its planned retirement date may be higher than the historical cost to operate that unit. For example, plant owners may need to re-hire workers who have already found alternative employment, which can increase labor costs. Fuel costs may also be higher than historical values, especially if plant owners are not able to commit to long-term contracts for coal, given the uncertainty about how long the Section 202(c) order will extend. Additionally, a plant owner may have ramped down maintenance as the expected retirement of the asset approached. This means there may be a backlog of deferred maintenance required at the time the plant is re-started.

Long-Term Cost Results

In the long term, sustaining capital expenditures could add $33.7 million per year to the cost of operating the units, using generic assumptions for annual capital spending as a function of coal unit age (Table 7). If DOE orders the units to operate through 2030, the net present value of sustaining capital expenditures from 2026–2030 would be $156 million, including $18 million for Culley 2, $69 million for Schahfer 17, and $68 million for Schahfer 18. These totals include the annual investment value only and not the total associated revenue requirement (i.e., they do not include the cost of capital). They also do not include the cost of any near-term repairs necessary to make a unit operable. We understand from NIPSCO remarks at a recent Indiana Utility Regulatory Commission forum that Schahfer 18 requires repairs that could take over six months to make it operable again.[18]

Available at: https://d18rn0p25nwr6d.cloudfront.net/CIK-0000201533/676cb715-625b-4823-9435-1f928f1880bd.pdf.

[18] David Speakman. WFFT-TV. “Earthjustice warns NIPSO to not pass on coal plant reopening costs to customers.” January 2, 2026. Available at: https://www.wfft.com/news/earthjustice-warns-nipsco-to-not-pass-on-coal-plant-reopening-costs-to-customers/article_5b0fdb80-4310-4328-83cf-5c7947ab6247.html.

Table 7. Estimate of sustaining capital expenditures if units remain online long-term

Quantity	Culley 2	Schahfer 17	Schahfer 18	Total
Cost in 2026 (thousands 2025$)	$3,957	$14,999	$14,793	$33,749
Net present value of costs 2026–2030 (thousands 2025$)	$18,235	$69,156	$68,218	$155,610

Source: Sargent & Lundy. 2018. Generating Unit Annual Capital and Life Extension Costs Analysis: Final Report on Modeling Aging-Related Capital and O&M Costs. Prepared for the U.S. Energy Information Administration. Available at: https://www.eia.gov/analysis/studies/powerplants/generationcost/pdf/full_report.pdf. Net present value calculation uses a discount rate of 7 percent, reflecting a typical nominal discount rate for a regulated utility.

As with the short-term costs, the estimates of sustaining capital expenditures presented here are conservative. Utilities tend to ramp down capital investment ahead of a unit's planned retirement. Utilities may also choose retirement when faced with high environmental compliance costs. This makes it more likely that units such as Culley and Schahfer operating beyond their planned retirement date will require substantial investments to replace aging equipment and ensure continued compliance with environmental regulations, beyond the investments necessary for units of similar age which had not planned to retire.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

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

Exhibit 6
DOE Order No. 202-17-4
Summary of Findings

Summary of Findings
Department of Energy Order No. 202-17-4

September 14, 2017

Section 202(c) of the Federal Power Act (FPA) (codified at 16 U.S.C. § 824a(c)), through section 301(b) of the Department of Energy Organization Act (codified at 42 U.S.C. § 7151(b)), authorizes the Secretary of Energy, upon finding "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes," to issue an order "requir[ing] . . . such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy as in [the Secretary's] judgment will best meet the emergency and serve the public interest." 16 U.S.C. § 824a(c)(1). If the order "may result in a conflict with [an] environmental law or regulation," then the Secretary must "ensure that such order requires generation, delivery, interchange, or transmission of electric energy only during hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable, is consistent with any applicable . . . environmental law or regulation and minimizes any adverse environmental impacts." *Id.* § 824a(c)(2). Orders issued under FPA section 202(c) "that may result in a conflict with [an] environmental law or regulation" expire 90 days after they are issued, but the Secretary "may renew or reissue such order[s] . . . for subsequent periods, not to exceed 90 days for each period, as [the Secretary] determines necessary to meet the emergency and serve the public interest." *Id.* § 824a(c)(4)(A).

The Department's regulations implementing FPA section 202(c) define the term "emergency" to mean, among other situations, "a specific inadequate power supply situation." 10 C.F.R. § 205.371. The regulations do not exhaustively list what qualifies as an emergency, but they note specifically that "[e]xtended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities can result in an emergency as contemplated in these regulations." *Id.*

On June 13, 2017, PJM filed a *Request for Emergency Order Pursuant to Section 202(c) of the Federal Power Act* (Order Application) (included in the docket[1] of this Order) with the Department "to preserve the reliability of [the] bulk power transmission system in the North Hampton Roads area." Virginia Electric and Power Company[2] (Dominion), the electric utility serving the area, owns the coal-fired, power generating Units 1 and 2 at the Yorktown Power Station in Yorktown, Virginia. In November 2011 and October 2012, Dominion notified PJM of its plan to deactivate Units 1 and 2, respectively, effective December 31, 2014, because the units were not equipped to

[1] The docket of this Order is available at https://www.energy.gov/oe/downloads/federal-power-act-section-202c-dominion-energy-virginia-june-2017.
[2] *See* Dominion Energy, Inc., Form 10-Q filing, at 1 (Aug. 3, 2017), included in the docket of this Order.

comply with the Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards (MATS), 40 C.F.R. part 63 subpart UUUUU. On June 24, 2014, pursuant to 40 C.F.R. § 63.6(i)(4)(i)(A), the Virginia Department of Environmental Quality granted Dominion a one-year MATS compliance extension for Yorktown Units 1 and 2.

On April 16, 2016, pursuant to section 113(a) of the Clean Air Act, 42 U.S.C. § 7413(a)(3) and (4), the EPA issued an Administrative Compliance Order (ACO) through April 15, 2017. The ACO implemented a 2011 MATS Enforcement Policy regarding issuance of section 113(a) administrative orders to sources that are unable to comply with the MATS but that may need to operate for up to a year to address a specific and documented reliability concern. The 2011 MATS Enforcement Policy was limited in application to units critical for reliability purposes. The EPA found that operation of Yorktown Units 1 and 2 met the policy criteria, as verified by the Federal Energy Regulatory Commission (FERC). Dominion has not achieved full compliance with the MATS for Yorktown Units 1 or 2 since the ACO expired, and section 113(a) of the Clean Air Act bars further compliance extensions.

Since Dominion's decision to retire the coal-fired Yorktown units, PJM has planned for their permanent deactivation by including required transmission upgrades in its own Regional Transmission Expansion Planning Process. PJM is subject to federal reliability standards enforced by the North American Electric Reliability Corporation (NERC), the Electric Reliability Organization designated by FERC. PJM holds the highest-level reliability responsibilities for the system it manages as a certified Reliability Coordinator, Balancing Authority, and Transmission Operator. PJM is also registered with NERC as a Planning Coordinator and Transmission Planner, among other functions. NERC Compliance Registry Active Entities List (updated Sept. 7, 2017), included in the docket of this Order. PJM applies reliability criteria to evaluate transmission system conditions and then develops the transmission solutions needed to ensure compliance with the reliability standards. The PJM Board of Managers approves those solutions in a Regional Transmission Expansion Plan (RTEP). Through its Transmission Expansion Advisory Committee (TEAC) and Sub-Regional RTEP Committees, PJM works with stakeholders throughout the RTEP's development. PJM Manual 14B, "Regional Planning Process," included in the docket of this Order. The PJM Board of Managers approved the transmission upgrades necessitated by the retirement of Yorktown Units 1 and 2 on May 17, 2012. TEAC Recommendations to the PJM Board (PJM Staff Whitepaper), May 2012, at 12, included in the docket of this Order.

PJM's approved solution was the Skiffes Creek Transmission Project, which consists of three components: a 500kV line, a 230kV line rebuild, and a new switching station. United States Army Corps of Engineers (Army Corps), Memorandum for the Record re: Department of the Army Environmental Assessment and Statement of Findings for the Above-Referenced Standard Individual Permit Application, CENAO-WR-RS (NAO-2012-00080 / 13-V0408), at 1, included in the docket of this Order. A number of issues in the North Hampton Roads area, many of which are interrelated, needed to be addressed to avoid overloading transmission lines with too much power, as detailed in PJM's Deactivation Study. Yorktown Units 1 and 2 Generator Deactivation Notification: Deactivation Study Results – updated June 26, 2017 (PJM Deactivation Study), included in the docket of this Order. *See also Va. Elec. & Power Co.*, Commission Comments on Requests for EPA Administrative Orders, Docket No. AD16-11-000, 153 FERC ¶ 61,265 at PP 14-16 (2015).

PJM completed a series of analyses consistent with RTEP procedures, finding that only the Skiffes Creek Transmission Project—and none of the stakeholder-proposed alternatives—addressed the full range of potential reliability violations. Order Application, app. I, at 16. For example, reliance on operation of the oil-fired Yorktown Unit 3 generator would not address thermal overload and voltage violations on the 230kV and 115kV bulk electric system that PJM identified because of significant environmental operating restrictions and other plant operation constraints associated with that unit, including an 8 percent capacity factor limitation. *See id.*, app. II, at 18. As a result, PJM did not recommend reliance on Yorktown Unit 3 as a sustainable alternative solution to the identified reliability criteria violations. *Id.*

As part of PJM's analyses, Dominion transmission staff provided PJM with an analysis of system needs as well as potential solutions to the retirement of generating units at Yorktown and elsewhere. Dominion Update to Retirement Study Results (Mar. 10, 2012), included in the docket of this Order. Dominion's analysis, which was based on PJM's initial determination of reliability criteria violations that needed to be addressed, was independently validated by PJM and publicly vetted through the PJM stakeholder process before PJM staff recommended that the Board of Managers approve the Skiffes Creek Transmission Project. PJM Staff Whitepaper at 12, included in the docket of this Order.

PJM, as the Regional Transmission Organization (RTO) responsible for transmission system operation across multiple states, including Virginia, maintains its expert determination that the Skiffes Creek Transmission Project is the most effective and efficient solution to address the identified reliability criteria violations. Order Application, app. I, at 16. As recently as March 1, 2017, PJM provided the Army Corps with an analysis of proposed alternatives and found that none of them sufficiently resolved the identified violations. Letter to Col. Jason E. Kelly, U.S. Army Corps of Engineers (Mar. 1, 2017), included in the docket of this Order. PJM's subsequent RTEP materials reaffirm the need for the Skiffes Creek Transmission Project, even considering the updated, steadily rising load forecasts in the recently released 2017 PJM Load Forecast Report (included in the docket of this Order). *See* PJM Interconnection, L.L.C., 2017 RTEP Process Scope & Input Assumptions, rev. 1, at 25-27 (Aug. 3, 2017), included in the docket of this Order.

Construction of the Skiffes Creek Transmission Project began in July 2017 and is expected to take approximately 18-20 months. *Order No. 202-17-2 Renewal Application Filing* (Renewal Application) at 3. Until the Project is completed, a plan known as the North Hampton Remedial Action Scheme (RAS) remains in effect. According to NERC's Glossary of Terms, a RAS is "[a] scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation ([megawatts] and [megavolt amperes (reactive)]), tripping load, or reconfiguring a System(s)." Glossary of Terms Used in NERC Reliability Standards (updated Aug. 1, 2017), at 24, included in the docket of this Order.

To preserve the grid's reliability, the North Hampton RAS would allow PJM, the grid operator, to drop load—that is, shut off power to certain customers—to prevent voltage collapse. Dominion presented this RAS to PJM in January 2017, and the SERC Reliability Corporation, the NERC-delegated regional reliability enforcement entity, approved it that same month. *See* Dave Rees, *Dominion Virginia Power Sets Plan for Emergency Blackouts*, Daily Press, Jan. 13, 2017, included in the docket of this Order. If Yorktown Units 1 and 2 were unavailable, many N-1-1 contingencies could result in voltage collapse and thermal overloads. New Remedial Action Scheme, North Hampton RAS (Presentation to PJM), at 4, included in the docket of this Order; PJM Deactivation Study, included in the docket of this Order. According to FERC, "An N-1-1 contingency is a sequence of events consisting of an initial loss of a single generator or transmission element, followed by system adjustment, followed by another loss of a single generator or transmission element." *Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators*, Docket No. AD14-14-000, 153 FERC ¶ 61,221 at P 30 n.61 (2015).

The North Hampton RAS is on standby for use at PJM's discretion. If PJM detects the loss of certain facilities, it could trip the remaining feeds to the Yorktown area and drop service to approximately 150,000 customers, preventing voltage collapse. Rotating outages would follow until the system returns to normal operating parameters. New Remedial Action Scheme, North Hampton RAS (Presentation to PJM), at 6, included in the docket of this Order. According to U.S. Census estimates, the region PJM identifies as the North Hampton Roads load area in its Order Application had a population of more than 660,000 as of July 2016. At a minimum, rotating outages under the RAS would therefore impact, directly or indirectly, several hundred thousand people. United States Census Bureau, QuickFacts database, available at https://www.census.gov/quickfacts/fact/table/US/PST045216.

On July 3, 2017, the Army Corps issued a permit to Dominion for the Skiffes Creek Transmission Project pursuant to section 10 of the Rivers and Harbors Act of 1899 (33 U.S.C. § 403) and section 404 of the Clean Water Act (33 U.S.C. § 1344). On July

10, 2017, Dominion commenced construction of the Skiffes Creek Transmission Project. Renewal Application at 3.

On August 24, 2017, PJM filed its Renewal Application with DOE. The filing included all reports required by Order No. 202-17-2 (included in the docket of this Order). PJM said that construction of the Project was still expected to take 18-20 months, and that periodic transmission outages would be necessary to proceed apace with the Project. The same day, Dominion wrote to the Department that it "agrees with the Renewal Application and will operate in accordance with its provisions." Further, Dominion acknowledged that a 202(c) order "is not a long term solution to the reliability issues in the North Hampton Roads area on the Virginia Peninsula." The Skiffes Creek Transmission Project, underway as of July 2017, is the long-term solution.

On September 7, 2017, the Department received comments from Sierra Club opposing PJM's renewal request. On September 13, 2017, the Department received an answer to Sierra Club's comments from PJM. Both documents are included in the docket of this Order.

Discussion

Order No. 202-17-2 directs operation of Yorktown Units 1 and 2 as needed to address reliability issues, subject to a dispatch methodology submitted to the Department for review. The reliability issues noted in Order No. 202-17-2 were described as Scenario One, increased load due to weather-related temperature extremes, and Scenario Two, decreased transmission capacity required by the RTEP upgrade. Scenario Two was contemplated but not yet applicable when Order No. 202-17-2 was issued because the Army Corps permit application for the Skiffes Creek Transmission Project was still pending. On July 3, the Army Corps issued Permit No. NAO-2012-00080, resulting in the potential need to operate Yorktown Units 1 and 2 to address both Scenario One and Two reliability issues. To date, in accordance with Order No. 202-17-2, PJM has directed operation of Yorktown Units 1 and/or 2 for all or part of 13 days. PJM Interconnection, L.L.C., Report on Yorktown Units 1 and 2 Operations Pursuant to Order No. 202-17-2, Attachment 1, included in the docket of this Order; Telephone call to Steven Pincus, Associate General Counsel, PJM, Sept. 11, 2017.

Scenario One applies when load conditions exceed a certain threshold due to local transmission issues that would cause PJM to operate the system outside its normal operating parameters.[3] Weather-related temperature extremes are one example of such a local transmission issue. Scenario Two is also triggered when load conditions exceed a certain threshold, but the threshold is lowered depending on the particular construction-related transmission outages in effect as the Skiffes Creek Transmission Project is built.

[3] Exact load thresholds were submitted as critical electric infrastructure information and are thus not described here so as not to provide vulnerability information on critical infrastructure.

Because the Project minimizes environmental impacts by utilizing existing transmission line rights-of-way to the extent possible, portions of existing transmission lines must be taken offline for upgrades. Under either scenario, when the relevant thresholds are exceeded, to prevent system overload and uncontrolled power disruptions, PJM must implement the North Hampton RAS. The only sufficient alternative to the RAS and its resulting outages for up to approximately 150,000 customers is the emergency operation of Yorktown Units 1 and 2. The demand response available to PJM is a small fraction of the load threshold and is "not sufficient to ensure reliable service." Order Application, app. II, at 18. Likewise, Dominion has limited demand-side management and curtailment capabilities, insufficient for reliability purposes even when fully deployed. *See id.*, app. III, at 21.

Activating the RAS would immediately interrupt service to load in the North Hampton Roads area. PJM asserts that, according to the RAS, during certain high load conditions, this "load shedding" could result in the loss of roughly 950 MW of electric power—that is, the loss of service to over 150,000 North Hampton Roads area customers. Order Application at 9. This service interruption could last hours or even days. *See* North Hampton RAS Presentation to PJM, at 8, included in the docket of this Order. Activating the RAS is not a gradual approach that presents a wide range of likely impacts; it is an extreme measure with immediate consequences to 150,000 customers. While the RAS is designed to prevent more catastrophic, uncontrolled grid impacts from occurring, load shedding of this magnitude is significant, and would trigger mandatory reporting both to DOE and FERC. DOE Form OE-417 requires reporting within one hour for "[l]oad shedding of 100 Megawatts or more implemented under emergency operational policy," and within six hours for "[l]oss of electric service to more than 50,000 customers for 1 hour or more." This is the same level of reporting triggered by a cyber or other hostile attack on grid resources. Form OE-417, Electric Emergency Incident and Disturbance Report, https://www.oe.netl.doe.gov/docs/OE417_Form_03312018.pdf. Similarly, FERC and NERC mandate notification for a variety of serious events including when a bulk electric system emergency triggers automatic load shedding of 100 MW or more, as in the RAS. *See* North American Electric Reliability Corporation, Reliability Standard EOP-004-3 (Event Reporting), http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-004-3&title=Event%20Reporting.

To underscore the potential impact of RAS activation, the estimated 150,000 impacted customers are counted by meter, not individual. One or more meters could translate to large household or commercial or industrial facilities, including those critical to health and safety systems. Whether counted as 150,000 or that amount multiplied several times over, the anticipated impact of this emergency situation is on par with or exceeds the impacts described in prior 202(c) orders. *Crisp Cnty. Power Comm'n v. Ga. Power Co.*, 35 FPC 629, 630-31 (1966) (ordering interconnection to prevent, in part, outages lasting more than an hour and affecting 500 to 2,000 customers on Crisp County, Georgia's system). *City of Cleveland, Ohio v. Cleveland Elec. Illuminating Co.*, 47 FPC 747, 749 (1972) (ensuring reliable service was provided to the approximately 20% of the city's consumers). Cleveland's 1970 Census-reported population was 750,903, suggesting that just over 150,000 individuals were affected by the 1972 202(c) order. *See* https://www.census.gov/population/www/documentation/twps0027/tab20.txt. As described earlier, the U.S. Census estimated the population of the North Hampton Roads load area at nearly 661,000 people just over a year ago.

A benefit of the planning efforts mandated by federal reliability standards is that entities such as PJM can accurately forecast the impacts to the bulk power system in steady-state and various contingency event situations. Thus, as reliability planning continues to mature, there should be fewer electric energy shortages that take bulk power system owners, operators, and regulators by surprise. That planners can identify conditions under which shortages may occur, however, does not rule out electric energy shortages constituting emergencies under FPA section 202(c) and the Department's implementing regulations. It is impossible to plan for every contingency, and challenges may arise even when implementing the most prudent plans. FPA section 202(c) affords the Secretary of Energy discretion in finding when an emergency exists and how best to meet the emergency and serve the public interest.

Here, an emergency exists due to the imminent possibility of implementing the North Hampton RAS under a range of both steady-state and contingency events, including potential transmission congestion preventing the delivery of available generation to the North Hampton Roads area. PJM Deactivation Study at 1-2, included in the docket of this Order. The RAS would leave approximately 150,000 customers without power, including residential, industrial, commercial, health and safety facilities, major national defense, and educational institutions. *See* Order Application, app. IV, at 30-31. That creates serious health and safety issues. Issuance of today's Order meets the emergency and serves the public interest.

In these circumstances, transmission outages, like those contemplated for or otherwise in connection with the construction of the Skiffes Creek Transmission Project, constitute an emergency for purposes of a section 202(c) order. As stated earlier, the Department's implementing regulations, in their current form since 1981, contemplate that "[e]xtended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities [may create] an emergency." 10 C.F.R. § 205.371. The regulations add that "[i]n such cases, the impacted 'entity' will be expected to make firm arrangements to resolve the problem until new facilities become available, so that a continuing emergency order is not needed." *Id.* PJM, the impacted entity in this case, requested today's Order. Through the RTEP, PJM made firm arrangements to resolve the problem through the Skiffes Creek Transmission Project, which is now permitted and under construction. That construction was delayed due to events beyond

PJM's control has no bearing on the likelihood of power outages for 150,000 customers. Such a power loss event would also constitute an emergency as contemplated by FERC in its Public Utility Regulatory Policies Act of 1978 regulations, which define "system emergency" as "a condition on a utility's system which is likely to result in imminent significant disruption of service to customers or is imminently likely to endanger life or property." 18 C.F.R. § 292.101(b)(4). The risk faced by 150,000 customers will continue, assuming the Skiffes Creek Transmission Project construction schedule is met, for approximately another 18 months. Today's Order is limited in time and specifically tailored to address an emergency contemplated both in the authorizing statute and the Department's implementing regulations.

Between 2005 and 2007, DOE issued orders under similar circumstances, directing the Mirant Potomac River Generation Station to operate until two new 230kV transmission lines could be built to ensure reliability to a portion of the District of Columbia. *See* Order No. 202-5-3 (relying on DOE regulatory definition of emergency as including extended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities). In a series of orders under FPA section 202(c), the Secretary ordered operation of the generation units while the two existing 230kV lines that supplied the central District of Columbia area were temporarily and sequentially removed from service to connect the new lines. Neither the problems leading up to the closure of the generating units nor the need for a particular transmission solution were unexpected. Nevertheless, the Department found that imminent power shortages, faced if contingency events occurred, constituted an emergency under the Federal Power Act. Order Nos. 202-5-3, 202-6-1, 202-6-2, 202-7-1, and 202-7-2.

In this matter, the likelihood of RAS activation is not theoretical. While Order No. 202-17-2 was in effect, PJM had to call upon Yorktown Units 1 and/or 2 on 13 days over three months. Absent Order No. 202-17-2, the RAS would have been activated instead. The alternatives available to PJM and Dominion are not sufficient to ensure reliability without available capacity from Yorktown Units 1 and 2. As described, PJM and Dominion cannot mobilize adequate alternatives to counter the loss of transmission during construction of the Skiffes Creek Transmission Project. For example, demand response resources, while potentially helpful at the margin, are insufficient to address either Scenario One or Scenario Two. *See* Order Application, app. II, at 18. Further, PJM's recent RTEP Input Assumptions and Scope Whitepaper indicates that Dominion theoretically has up to 130 MW of distributed solar generation available during the summer. 2017 RTEP Process Scope and Input Assumptions, rev. 1, tbl.3.2, at 18 (Aug. 3, 2017), included in the docket of this Order. Outside of ramp-up and ramp-down times, each Yorktown Unit typically ran at 100 MW output or higher, day or night, when operational while Order No. 202-17-2 was in effect. PJM Interconnection, L.L.C., Report on Yorktown Units 1 and 2 Operations Pursuant to Order No. 202-17-2, Attachment 1. Distributed generation is an intermittent resource; even under ideal conditions, with full-capacity, daytime generation and load reduction at the height of the summer, distributed generation generally would still not have offset the baseload generating capacity needed to ensure reliability on the North Hampton Roads area grid. And any flexibility for scheduling the Skiffes Creek Transmission Project's construction during historically low-load periods ended when the EPA ACO expired, as expeditious completion of the Project is now the priority. Therefore, even if PJM and Dominion made full use of available alternatives, capacity from Yorktown Unit 1, 2, or both would still be necessary to meet the emergency and serve the public interest.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law or regulation be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable, [be] consistent with any applicable . . . environmental law or regulation and minimize[] any adverse environmental impacts." Certain load conditions may necessitate operation of Yorktown Units 1 and 2.

To minimize the hours of operation and adverse environmental impacts, the Order contains certain limitations. First, DOE maintains consistency with EPA's approach in the 2016 ACO by authorizing operation of Yorktown Units 1 and 2 only when called upon by PJM for reliability purposes. The Department consulted with EPA and has reviewed data provided by PJM and Dominion on operations, air emissions, and water usage. This Order will continue the operational limitations described in EPA's above-referenced ACO, AED-CAA-113(a)-2016-0005. Second, DOE requires that PJM and Dominion, consistent with good utility practice, first exhaust all reasonably and practically available resources, including demand response and behind-the-meter generation resources, before operating Yorktown Units 1 and 2. Third, DOE requires continued compliance with the June 27 dispatch methodology, which was reviewed by the Department, and which remains subject to continuing oversight by the Department. In particular, the dispatch methodology establishes Yorktown Units 1 and 2 commitment procedures, describes the utilization and trip conditions of the North Hampton RAS for mitigating congestion on the Virginia Peninsula or North Hampton Roads area, and describes Dominion's mitigation options for the existing James River tower contingency. The dispatch methodology is an operating protocol that limits the ability of PJM to dispatch Yorktown Units 1 and 2 only when needed to mitigate reliability issues associated with scheduled and emergency transmission outages directly related to the Skiffes Creek Transmission Project and other local transmission issues. The EPA ACO recognized that such a dispatch methodology, under which PJM determines when the Yorktown units are needed for reliability issues, serves the objective of minimizing emissions. ACO at 8-9, included in the docket of this Order. Fourth, to track when Yorktown Units 1 and 2 are operated to maintain grid reliability and to monitor associated air emissions and water usage, reports will be required every two weeks going forward. If the Department becomes concerned with PJM or Dominion's compliance with this Order, enforcement actions are available, up to and including termination of the underlying order.

While DOE has constrained PJM's operations with regard to Yorktown Units 1 and 2, it is necessary to preserve reasonable discretion for PJM, as a Transmission Operator, to address the second-to-second operational challenges of grid management. This follows DOE's practice in earlier orders issued under FPA section 202(c), which prioritized reliability concerns as identified and assessed by the operator. For example, Order No. 202-02-1 (Aug. 16, 2002) ordered Cross-Sound Cable Company, LLC to operate a cable across Long Island Sound, limiting "transmission and delivery of . . . electric capacity and/or energy [to that] necessary in the judgment of the New York Independent System Operator [ISO] to meet the supply and essential reserve margin needs of the Long Island Power Authority [LIPA]," but only "in order for LIPA to serve its firm retail customers after it has implemented all available load reduction measures consistent with good utility practice." Order No. 202-03-1 (Aug. 14, 2003) directed operation of the same cable, but specifically ordered the New York ISO and ISO New England to require Cross-Sound Cable Company to operate the cable. That order also required both RTOs to "consult with each other and with appropriate reliability organizations." Today's Order similarly requires PJM to identify and mitigate reliability issues in accordance with DOE's specified operational limitations.

In considering renewal or reissuance of an order under FPA section 202(c) that may conflict with an environmental law or regulation, DOE is required to "consult with the primary Federal agency with expertise in the environmental interest protected by such law or regulation" and to include "conditions as such Federal agency determines necessary . . . to the extent practicable." 16 U.S.C. § 824a(c)(4). The EPA is the primary federal agency in this case with expertise in the protected environmental interest, specifically MATS and section 316(b) of the Clean Water Act, and the Department consulted with EPA after receiving the Renewal Application. Email from Acting Assistant Administrator Starfield, Office of Enforcement and Compliance Assurance, to Acting Under Secretary for Science and Energy Hoffman (Sept. 11, 2017), included in the docket of this Order. After consulting with EPA, and consistent with that consultation, the Department found that the only appropriate short-term emissions limitation on Yorktown Units 1 and 2 would be to curtail operating hours to the maximum extent practical for reliability purposes.

Pursuant to the National Environmental Policy Act of 1969, the Department has determined that issuance of this Order fits within the category of actions included in Categorical Exclusion (CX) B4.4 and otherwise meets the requirements for application of a CX. The Order fits within the category of actions because it authorizes "[p]ower marketing services and power management activities (including, but not limited to, storage, load shaping and balancing, seasonal exchanges, and other similar activities), provided that the operations of generating projects would remain within normal operating limits." Records of Categorical Exclusion Determination, Order No. 202-17-4, Sept. 11, 2017, included in the docket of this Order.

For the reasons stated above, the Secretary of Energy finds that an emergency exists threatening imminent electric energy shortages, and that this Order is necessary to address the emergency and serve the public interest in the North Hampton Roads area. The limitations on operation set forth in Order No. 202-17-4 and outlined above are, to the maximum extent practicable, consistent with applicable environmental laws or regulation and minimize any adverse environmental impacts, and the reporting requirements for operations and estimated emissions ensure transparency of implementation.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

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

Exhibit 7
DOE Order No. 202-02-1

Department of Energy
Washington, DC 20585

Order No. 202-02-1

Pursuant to the authority vested in me by section 202(c) of the Federal Power Act, 16 U.S.C. 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. 7151(b), I hereby determine that an emergency exists on Long Island in the State of New York due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, a shortage of facilities for the transmission of electric energy and other causes, and that issuance of this order will alleviate the emergency and serve the public interest. Based on this determination, I hereby order:

From the effective date and time of this order until 12:01 a.m. Eastern Daylight Time, October 1, 2002, Cross-Sound Cable Company, LLC is directed to operate the Cross-Sound Cable and related facilities connecting substations in New Haven, Connecticut and Shoreham, Long Island, New York, to transmit and deliver electric capacity and/or energy when, as and in such amounts as may be scheduled and purchased by the Long Island Power Authority (LIPA), and to take such actions as are necessary in order to enable it to do so, including but not limited to energizing and continuing to energize the facilities of Cross-Sound Cable Company, LLC; *provided*, that this order otherwise shall be limited to requiring the transmission and delivery of such electric capacity and/or energy as is necessary in the judgment of the New York Independent System Operator to meet the supply and essential reserve margin needs of LIPA, in order for LIPA to serve its firm retail customers after it has implemented all available load reduction measures consistent with good utility practice, including curtailing and/or terminating service to interruptible customers, public appeals for conservation, reducing 30 minute reserves to zero, and implementing voltage reductions; *and provided further*, that prior to exercising its judgment as required by this order, the New York Independent System Operator must consult with ISO New England, Inc. to ensure that the scheduling of such electric capacity and/or energy will not violate system operating criteria, and the New York Independent System Operator should, as practicable, consult with appropriate reliability organizations. If necessary, just and reasonable terms for the transmission and delivery of electric capacity and/or energy pursuant to this order, including the compensation therefor, shall be established by a supplemental order issued pursuant to Federal Power Act section 202(c).

Nothing in this order shall preclude use of the energized Cross-Sound Cable and its related facilities connecting substations in New Haven, Connecticut and Shoreham, Long Island, New York, to transmit and deliver electric capacity and/or energy from Long Island to Connecticut or from Connecticut to Long Island in accordance with the operating and scheduling protocols and decisions of the New York Independent System Operator and ISO New England, Inc.

This order shall be effective upon its issuance.

Issued in Washington, D.C. at 2:38PM this 16th day of August, 2002.

Spencer Abraham
Secretary of Energy

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

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

Exhibit 8
Cooke Email to Alle-Murphy

-----Original Message-----
From: Alle-Murphy, Linda
Sent: Wednesday, December 28, 2005 9:05 AM
To: Mansueti, Lawrence
Subject: Re: Order No. 202-05-3

Dear Mr. Mansueti,

I am an associate at Schnader Harrison Segal and Lewis, working together with John Britton, who represents the City of Alexandria in the Mirant Power Plant matter. I have a few procedural questions regarding the application for rehearing.

According to Section VI.H. of Order No. 202-05-3, applications for rehearing in this matter should be addressed to you. Section VI.H. cites to 16 U.S.C. Section 825(l), which refers to the "Commission" (FERC). I am just seeking to confirm that Section 825(l) also applies to this DOE proceeding.

Also, are 10 CFR Section 1003.1 et seq., Office of Hearings and Appeals Procedural Regulations applicable to this proceeding (e.g. re service requirements, etc.) If not, are there other procedural rules that apply to this proceeding?

Thank you very much for your assistance! You may respond by return e-mail or, if that is not convenient for you, by telephone or fax.

Linda Alle-Murphy
Linda B. Alle-Murphy
Schnader Harrison Segal & Lewis LLP
1600 Market Street, Suite 3600
Philadelphia, PA 19103-7286

From: Cooke, Lot
Sent: Friday, December 30, 2005 8:51 AM
To: 'LAlle-Murphy@Schnader.com'
Subject: Rehearing procedures for DOE Order No. 202-05-3

Dear Ms. Alle-Murphy:

In response to your emailed question to Mr. Mansueti--

The DOE Organization Act transferred the authority of the Federal Power Commission to the Secretary, except for authority over rates and charges for the transmission and sale of electric energy, which was transferred to FERC. Federal Power Act (FPA) Section 202(c) emergency authority was generally and specifically given to the Secretary.

An order issued under the FPA is only reviewable pursuant to the rehearing provisions contained in section 313 of the FPA, so that is the applicable provision under which to seek rehearing of the December 20,
2005 order.

The DOE regulations on emergency orders, 10 CFR section 205.370, et seq., do not a have specific rehearing section, but a party seeking rehearing can look for procedural guidance to FERC's Rules of Practice and Procedure, 18 CFR Part 385. In particular the rehearing regulations contained at 18 CFR section 385.713 and the service requirement contained at 18 CFR section 385.2010. The Office of Hearings and Appeals procedures are not applicable as the Secretary will make the rehearing decision pursuant to FPA section 313.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

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

Exhibit 9
DOE Order No. 202-22-4

Department of Energy
Washington, DC 20585

Order No. 202-22-4

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and delegated by email correspondence (Dec. 23, 2022), and for the reasons set forth below, I hereby determine that an emergency exists in the electricity grid operated by PJM Interconnection, LLC (PJM) due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

Emergency Situation

On December 24, 2022, PJM, the Regional Transmission Operator (RTO) for 65 million people in thirteen states and the District of Columbia (the PJM Region), filed a *Request for Emergency Order Under Section 202(c) of the Federal Power Act* (Application) with the United States Department of Energy (Department) "to preserve the reliability of the bulk electric power system."

The PJM Region, like many regions across the country, is currently being affected by a severe winter weather system. PJM states that this weather system caused a significant drop in temperatures across the PJM Region on December 23, 2022, accompanied by high winds in excess of 40 mph. As a consequence of the impact of wind and decreasing temperatures, the demand for electricity in the PJM Region rose to an unusually high peak load on the evening of December 23, 2022, in excess of 135,000 MW. This severely cold weather is expected to last through Sunday morning.

While the vast majority of generating units in the PJM Region continue to function adequately under these stressed conditions, some units have experienced operating difficulties due to cold weather or fuel limitations, primarily gas. Specifically, approximately 45,000 MW of generating units (the majority of which are thermal) are currently outaged or derated. PJM has expressed its concern that these units will be unable to return to service over at least the next 48 hours, which coincides with the time period for which PJM is requesting this Order. Since these units may not promptly return to service, and in the event PJM experiences additional generating unit outages, PJM states that it may need to curtail some amount of firm load on December 24, December 25, or December 26, 2022 in order to maintain the security and reliability of the PJM system.

Description of Mitigation Measures

In its Application, PJM identifies the measures it is taking to ensure the supply of generation will continue to be sufficient to meet system demand and reserve requirements. On December 20, 2022, PJM issued a cold weather advisory in the PJM Region in anticipation of the forecasted weather conditions. Then on December 23, 2022, PJM issued a PJM Region-wide cold weather alert which further highlighted PJM's expected need to call higher-than-normal generation resources in light of the anticipated weather.

On December 23, 2022, generating reserves diminished to a level that required PJM to declare an Energy Emergency Alert (EEA) Level 2 and take other emergency actions. PJM states that after having exhausted economic operation, PJM triggered a Maximum Generation Emergency Action to increase the PJM Region generation above the maximum economic level. Further, PJM triggered its load management reduction actions to provide additional load relief by using PJM-controllable load management programs. PJM called on demand response providers and curtailment service providers to reduce load. PJM also issued public appeals for consumers to reduce usage. PJM has continued to employ these emergency actions through December 24, 2022, and anticipates needing to continue them through the order end date that it has requested.

Since December 23, 2022, PJM has also taken additional measures to provide additional reserves, including:

- Reducing exports to neighboring regions and requested shared reserves for neighboring regions; consistent with joint operating agreements and other regulatory requirements, PJM has continued to communicate and collaborate with its interconnected neighboring systems when the demand on the PJM system has exceeded expected energy and reserve requirements and when emergency transfers were required to support PJM's interconnected neighboring systems;
- Issuing additional public conservation appeals;
- Running uneconomic generation during lower load periods to ensure their availability during peak conditions;
- Utilizing its Emergency Procedures to assist in maximizing the pumped storage hydro generation levels;
- Communicating and preparing transmission and distribution service providers to implement distribution voltage reduction measures; and
- Communicating and preparing transmission and distribution service providers to implement firm load shed.

In its Application, PJM committed to continue to take such actions, including utilizing other supply resources before calling upon any generators to operate in excess of permitting levels. According to PJM, it is nevertheless possible that the measures it has and will take may not be sufficient to avoid the need to curtail firm load in order to ensure system reliability.

Request for Order

PJM requests that the Secretary issue an order immediately, effective today, December 24, 2022, through 12:00 p.m. Eastern Time on Monday, December 26, 2022, authorizing the electric generating units identified in Exhibit A, as well as any other generating units subject to emissions or other permit limitations in the PJM Region to operate up to their maximum generation output levels under the limited circumstances described in this Order, notwithstanding air quality or other permit limitations. The generating units (Specified Resources) that this Order pertains to are listed on the Order 202-22-4 Resources List, as described below.

ORDER

Given the emergency nature of the expected load stress, the responsibility of PJM to ensure maximum reliability on its system, and the ability of PJM to identify and dispatch generation necessary to meet the additional load, I have determined that, under the conditions specified below, additional dispatch of the Specified Resources is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). This determination is based on, among other things:

- The emergency nature of the expected load stress caused by the current cold weather event threatens to cause loss of power to homes and local businesses in the areas that may be affected by curtailments, presenting a risk to public health and safety.
- The expected shortage of electric energy, shortage of facilities for the generation of electric energy, and other causes in the PJM Region demonstrate the need for the Specified Resources to contribute to the reliability of the PJM Region.
- PJM is responsible to ensure maximum reliability on its system, and, with the authority granted in this Order, its ability to identify and dispatch generation, including the Specified Resources, necessary to meet the additional load resulting from the cold weather event is enhanced.

In line with the anticipated circumstances precipitated by the cold weather event, this Order is limited to the period beginning with the issuance of this Order on December 24, 2022 through 12:00 pm Eastern Time on December 26, 2022. Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation on the conditions contained in this Order, with reporting requirements as described below.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts. PJM anticipates that this Order may result in exceedance of emissions of sulfur dioxide, nitrogen oxide, mercury, and carbon monoxide emissions, as well as wastewater release limits. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by PJM for reliability purposes.

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

A. From the time this Order is issued on December 24, 2022, to 12:00 pm Eastern Time on December 26, 2022, in the event that PJM determines that generation from the Specified Resources is necessary to meet the electricity demand that PJM anticipates in the PJM Region during this event, I direct PJM to dispatch such unit or units and to order their operation only as needed to maintain the reliability of the power grid in the PJM Region when the demand on the PJM system exceeds expected energy and reserve requirements. Specified Resources are those generating units set forth on the Order 202-22-4 Resource List, subject to updates directed here and as described in paragraph D, which the Department shall post on www.energy.gov.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by PJM for reliability purposes. Consistent with good utility practice, PJM shall exhaust all reasonably and practically available resources, including available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions, to the extent that such resources provide support to maintain grid reliability, prior to dispatching the Specified Resources. PJM shall provide a daily notification to the Department reporting each generating unit that has been designated to use the allowance and operated in reliance on the allowances contained in this Order.

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

(i) For any generation resource whose operator notifies PJM that the unit is unable, or expected to be unable, to produce at its maximum output due to an emissions or other limit in any federal environmental permit, and during the pendency of a PJM-triggered Maximum Generation Emergency Action, at any point before 12:00 Eastern Time on Monday, December 26, 2022, the unit will be allowed to exceed any such limit only during any period for which PJM has declared an Energy Emergency Alert (EEA) Level 2 or Level 3 (during which time PJM will have triggered a Maximum Generation Emergency Action), except as described in item (iii) below in certain limited circumstances in anticipation of an EEA Level 2. Once PJM declares that the EEA Level 2 event has ended, the unit would be required to immediately return to operation within its permitted limits. And at all other times, the unit would be required to operate within its permitted limits, except for the limited exceptions provided herein for operations in anticipation of an EEA Level 2 to prevent the cycling of units or facilitate the charging or pumping of other resources necessary for the EEA Level 2.

(ii) For any generation resource whose operator notifies PJM that the unit is offline or would need to go offline at any point before 12:00 Eastern Time on Monday, December 26, 2022, due to an emissions or other limit in any federal environmental permit, PJM may direct the unit operator to bring the unit online, or to keep the unit online, and to operate at the level consistent with its permits but subject to the exceptions set forth in this Order. In this circumstance, the operator is allowed to make all of the unit's capacity available to PJM for dispatch during any period for which PJM has declared an EEA Level 2 or 3 (during which time PJM has triggered a Maximum Generation Emergency Action), except as described in item (iii) below in certain limited circumstances in anticipation of an EEA Level 2. Once PJM declares that such an EEA Level 2 event has ended and the Maximum Generation Emergency Action is discontinued, the unit would be required to immediately return to operating at a level below the higher of its minimum operating level or the maximum output allowable under the permitted limit.

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

(iv) To minimize adverse environmental impacts as set forth herein, this Order limits operation of dispatched units to the times and within the parameters determined by PJM for reliability purposes. Consistent with good utility practice, and notwithstanding standard merit order dispatch, PJM shall exhaust all reasonably and practically available resources, including available imports, demand response and identified behind-the-meter generation resources selected to minimize an increase in emissions to the extent that such resources provide support to maintain grid reliability prior to dispatching the Specified Resources at levels above their permitted emissions levels. PJM shall provide a daily notification to the Department reporting each generating unit that has been designated to use the allowance and operated in reliance on the allowances contained in this Order.

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

D. In the event that PJM identifies additional generation units that it deems necessary to operate in excess of federal environmental permitting limits in order to maintain the reliability of the power grid in the PJM Region when the demand on the PJM system exceeds expected energy and reserve requirements, PJM shall provide prompt written notice to the Department of Energy at AskCR@hq.doe.gov with the name and location of those units that PJM has identified, as well as additional notice by the same means through updating Exhibit A to its Application with such additional generation units, the fuel type of such unit, and the anticipated category of environmental impact, at 09:00 Eastern Time or 21:00 Eastern Time, whichever follows closest in time to the unit identification by PJM to the greatest extent feasible. Such additional generation unit shall be deemed a Specified Resource for the purpose of this Order for the hours prior to the required written notice to the Department updating Exhibit A, and PJM may dispatch such additional generation units, provided that if the Department of Energy notifies PJM that it does not approve of such generation unit being designated as a Specified Resource, such generation unit shall not constitute a Specified Resource upon notification from the Department. The Department shall post an updated Order 202-22-4 Resource List as soon as practicable following notification from PJM under this paragraph.

E. PJM shall provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time. By January 26, 2023, PJM shall report all dates between December 24, 2022, and December 26, 2022, inclusive, on which the Specified Resources were operated, the hours of operation, and exceedance of permitting limits, including sulfur dioxide, nitrogen oxide, mercury, carbon monoxide, and other air pollutants, as well as exceedances of wastewater release limits. PJM shall submit a final report by February 27, 2023, with any revisions to the information reported on January 26, 2023. The environmental information submitted in the final report shall also include the following information:

(i) Emissions data in pounds per hour for each Specified Resource unit, for each hour of the operational scenario, for CO, NOx, PM10, VOC, and SO2;

(ii) Emissions data must include emissions (lbs/hr) calculated consistent with reporting obligations pursuant to operating permits, permitted operating/emission limits, and the actual incremental emissions above the permit limits;

(iii) The number and actual hours each day that each Specified Resource unit operated in excess of permit limits or conditions, e.g., "Generator #1; December 25, 2022; 4 hours; 04:00-08:00 CT";

(iv) Amount, type and formulation of any fuel used by each Specified Resource;

(v) All reporting provided under the Specified Resource's operating permit requirements over the last three years to the United States Environmental Protection Agency or local Air Quality Management District for the location of a Specified Resource that operates pursuant to this Order;

(vi) Additional information requested by DOE as it performs any environmental review relating to the issuance of this Order; and

(vii) Information provided by the Specified Resource describing how the requirements in paragraph C above were met by the Specified Resource while operating under the provisions of this Order.

In addition, PJM shall provide information to the Department quantifying the net revenue in aggregate associated with generation in excess of environmental limits in connection with orders issued by the Department pursuant to Section 202(c) of the Federal Power Act.

F. PJM shall take reasonable measures to inform affected communities where all Specified Resources operate that PJM has been issued this Order, in a manner that ensures that as many members of the community as possible are aware of the Order, and explains clearly what the Order allows PJM to do. At a minimum, PJM shall post a description of this Order on its website (with a link to this Order) and identify the name, municipality or other political subdivision, and zip code of Specified Resources covered by this Order, as the Specified Resources may be updated pursuant to paragraph D above. In addition, in the event that a Specified Resource operates pursuant to this Order, a general description of the action authorized by this Order will be included in any press release issued by PJM with respect to the cold weather event and will include a reference to the website posting required by the preceding sentence for further information. PJM shall describe the actions taken to comply with this paragraph in the reports delivered to the Department pursuant to paragraph E above.

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

H. PJM shall be responsible for the reasonable third-party costs of performing analysis of the environmental and environmental justice impacts of this Order, including any analysis conducted pursuant to the National Environmental Policy Act.

I. This Order shall be effective upon its issuance, and shall expire at 12:00 Eastern Time on Monday, December 26, 2022, with the exception of the reporting requirements in paragraph E. Renewal of this Order, should it be needed, must be requested before this Order expires.

Issued in Washington, D.C. at 5:30 PM Eastern Standard Time on this 24th day of December 2022.

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Undersecretary of Energy for Infrastructure

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

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

Exhibit 10
Grid Strategies June Report

A Review of DOE's 202(c) Order for the Campbell Coal Plant

Michael Goggin

June 18, 2025

I. Executive Summary

On May 23, 2025, the U.S. Department of Energy ("DOE") issued an order under Section 202(c) of the Federal Power Act directing the Midcontinent Independent System Operator ("MISO") and utility Consumers Energy to take "all measures necessary" to ensure the continued availability of the J.H. Campbell coal power plant in Michigan for three months, past its scheduled retirement date on May 31, 2025.[1] The DOE order claims there is an emergency due to insufficient "dispatchable capacity" in MISO. The order does not define dispatchable capacity and does not clearly indicate the basis on which the Energy Secretary believes there is a shortfall of dispatchable resources. In my experience, "dispatchable" generally refers to generating resources that can change their level of output on command, and a stated lack of "capacity" is a claim that there will be insufficient electricity supply during periods of peak demand, a need often referred to as "resource adequacy."

This report is organized into four sections. First, it provides brief background on the methods grid planners use to ensure electricity supply is adequate to meet demand. Next, it reviews how utilities, state regulators, regional grid operators, and reliability regulators use planning, regulatory, and market mechanisms to ensure electricity generating supply is adequate to meet demand. Third, it reviews the determinations Consumers Energy, Michigan, and MISO have already made that the Campbell plant is not necessary for meeting anticipated electricity demand this summer, in large part because MISO has a summer capacity surplus of more than 2,600 MW. That section also documents why the North American Electric Reliability Corporation ("NERC") Summer Reliability Assessment that DOE cites to justify its order does not indicate that an emergency exists in the MISO region. Finally, the report explains why the aging Campbell plant is a poor choice for meeting electricity demand this summer, as evidenced by its low availability rates during recent summer peak demand periods.

II. Background on Resource Adequacy Methods

At the outset, it is helpful to explain some relevant terms. "Resource adequacy" generally means having enough supply during periods of peak net system need from generators and from other resources like demand response (programs by which electricity users are compensated for reducing consumption) and energy storage.

There is no one correct amount of resource adequacy: what level is appropriate depends in part on what system planners, regulators, industry, utilities, customers, government, and other stakeholders want to pay for. This question is one of risk versus reward. More resources can always be added to achieve more resource adequacy, but there are diminishing returns if more is invested. As a result, the usual benchmark for acceptable risk of such events occurring is one day of lost load in ten years. In other words, system planners typically seek to have a set of

[1] U.S. DOE, *Order No. 202-25-3*, (May 23, 2025) available at https://www.energy.gov/sites/default/files/2025-05/Midcontinent%20Independent%20System%20Operator%20%28MISO%29%20202%28c%29%20Order_1.pdf

resources such that the system can expect to experience no more than one day containing an outage in ten years. Utilities, state regulators, and regional grid operators have coalesced around this benchmark, and have generally concluded that it appropriately balances the cost of building and maintaining generating capacity versus the cost of potential generation shortfalls. Many state regulators use the one day in ten years criterion to ensure profit-maximizing utilities do not burden ratepayers with the cost of excessive generating capacity. This is largely due to the diminishing marginal returns from a higher planning reserve margin,[2] which is the amount of extra generating capacity that exists in a system above peak load projections, expressed as a percentage of peak load.

To calculate the target reserve margin that achieves a specific risk threshold, planners use sophisticated statistical analyses to simulate electricity demand and supply availability scenarios based on decades of historical weather patterns. The reserve margin thus accounts for interannual variability in peak electricity demand due to extreme weather events and other factors. Planners also use these sophisticated methods to determine the expected contribution of each resource towards meeting peak needs, often called a resource's "capacity value" or "accredited capacity." These methods account for how weather patterns affect the timing of wind and solar output, and how unplanned outages and other factors can cause any resource to have reduced availability during periods of need.[3] Thus, planners account for all of these risks in setting the target reserve margin.

II. Existing State and Regional Measures Already Ensure Reliability and Resource Adequacy.

The regulation and oversight of power grid reliability and resource adequacy have become far more sophisticated and robust since Section 202(c) of the FPA was enacted in 1935. For most of the past century, states and the electric utilities they regulate have had front-line responsibility for ensuring that adequate resources are available to serve the electric power needs of customers in their jurisdictions. In recent decades, two key developments have layered regional and national assurance mechanisms onto the existing state resource adequacy regulations.

First, the Federal Energy Regulatory Commission ("FERC") approved the formation of Regional Transmission Organizations ("RTOs") and Independent System Operators ("ISOs"),

[2] For example, see K. Carden and A. Dombrowsky, *Estimation of the Market Equilibrium and Economically Optimal Reserve Margins for the ERCOT Region for 2024 (Final),* (January 2021) available at https://www.ercot.com/files/docs/2021/01/15/2020_ERCOT_Reserve_Margin_Study_Report_FINAL_1-15-2021.pdf, at 34-40; and PJM, *2023 PJM Reserve Requirement Study*, (October 2023) available at https://www.pjm.com/-/media/DotCom/committees-groups/committees/mc/2023/20231115/20231115-consent-agenda-b---2-2023-pjm-reserve-requirement-study-report-final.ashx, at 27.

[3] MISO, *Planning Year 2025-2026 Loss of Load Expectation Study Report*, available at https://cdn.misoenergy.org/PY%202025-2026%20LOLE%20Study%20Report685316.pdf?v=20250313114401, at 20-23.

such as MISO. The RTOs and ISOs operate the bulk power transmission system within their service areas – which in several cases (including MISO) cover multiple states – and manage wholesale electricity markets that help ensure resource adequacy.

Second, Congress enacted Section 215 of the FPA in 2005, creating a new reliability regulatory regime overseen by FERC. Pursuant to Section 215, FERC designated NERC as the national Electric Reliability Organization, with responsibility for setting and enforcing national reliability standards, subject to FERC approval. NERC also designates "Regional Entities" that help implement the national standards in their regions and develop region-specific standards, subject to FERC and NERC approval. ReliabilityFirst Corporation ("RFC") is the Regional Entity for Michigan and most of eastern MISO. Together, state utility regulators, ISOs and RTOs, NERC and its subsidiary regional reliability organizations, and FERC share responsibility for assuring the electric grid operates reliably.

A. States and Utilities

The states are responsible for ensuring that the utilities they regulate have adequate resources to meet demand for electric power. In most states, including Michigan, utility regulators have processes through which they evaluate utilities' plans to add new generators, retire old generators, and undertake a host of other activities, with the goal being to identify a prudent resource plan that minimizes costs and risks for ratepayers. I have participated in many of these "integrated resource plan" or "IRP" proceedings, which are detailed, fact-intensive processes in which the regulator and other stakeholders closely review a utility's proposed assumptions and methods. A primary focus of IRP proceedings is ensuring resource adequacy. State regulators have strong incentives to ensure resource adequacy, as a generation shortfall in a state can result in localized blackouts or increased costs for ratepayers.

B. MISO

MISO plays two important roles in ensuring resource adequacy. First, as discussed further below, MISO is a designated Planning Coordinator responsible for implementing the resource adequacy planning standard adopted by RFC. Pursuant to that standard, MISO performs and documents an annual resource adequacy analysis, which is based on the "one day in ten years" loss of load standard. MISO uses that analysis to determine a planning reserve margin for the region, for each season of the upcoming year. MISO then applies that margin to each zone's load projections to determine the planning reserve margin requirement for each zone and season.

Second, MISO runs a residual capacity market that allows utilities and generators to buy and sell capacity to meet each of their four seasonal planning reserve margin requirements. MISO and other grid operators also use energy markets and other tools to ensure that electricity supply meets demand at all times. Each of these markets is discussed in more detail below.

1. Capacity Market

First, MISO sets the planning reserve margin that it determines is required to meet the "one day in ten years" benchmark, and determines resources' capacity accreditation, as discussed above. MISO then applies the planning reserve margin to each zone of MISO. As part of this, MISO uses power flow models to assess how transmission constraints affect the need for generation in each zone in the MISO region.[4] This ensures that there are sufficient resources to meet demand in each zone, after accounting for the transmission capacity available to import power from other zones.

Based on these inputs and zonal requirements, MISO then conducts an annual capacity market auction, and this price signal provides an additional mechanism to incentivize the development and construction of new generation to help meet future resource adequacy needs. The core elements of MISO's capacity market processes have been approved by FERC under its authority to ensure that rates are just, reasonable, and not unduly discriminatory under Section 205 of the Federal Power Act.[5]

If a utility falls short of its resource adequacy obligation to meet its needs plus MISO's reserve margin, it must make up for that shortfall through purchases in the capacity market. If supply is short or import purchases begin to approach the import limit MISO has calculated for a given zone, the price of capacity in that zone will increase. State regulators are cognizant of that risk, and thus have a strong incentive to ensure their utilities have adequate supplies in advance.

2. Real-Time and Near-Term Operations

Each day MISO runs a day-ahead energy market in which generators offer to produce electricity each hour of the next day at a certain price. MISO then compares this supply curve of offers to its demand forecast for the next day, and then "commits" the generators that can meet this demand forecast at lowest cost subject to reliability and transmission constraints. Generators that are committed but were offline start and take other steps required to be online by the next day. The vast majority of electricity is procured in the day-ahead market, but MISO also runs a real-time energy market to fine-tune deviations in supply and demand that occur after the day-ahead market has concluded. The energy markets play an important role in ensuring supply is adequate to meet demand by sending a powerful price signal for generators to maximize their output and for utilities to import power from neighboring regions during periods of need.

MISO also operates "ancillary services" markets, which procure other services like operating reserves from flexible resources that help balance fast variability in supply and demand. Prices in these markets are typically very low as MISO has a large supply of flexible

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[4] *Id.* at 36-55.
[5] FERC Docket Nos. 11-4081; EL15-70 *et al*.; ER22-495; ER23-2977; ER24-1638.

resources,[6] and that supply is increasing as batteries and other flexible resources replace inflexible coal and nuclear generators.

As a result, there is no indication of a need for "dispatchable" resources, as claimed by DOE's Order, to provide additional flexibility in MISO. If a need for more flexibility arose at any point in time, prices for ancillary services would simply increase, spurring flexible generators that were offline to start up and provide flexibility until the need has passed. Regardless, coal plants like Campbell are not very dispatchable compared to other generating resources, with long startup times, slow output ramp rates, and high minimum output levels. This can also reduce their capacity contribution to meeting peak demand needs, particularly those that arise on short notice.

If MISO encounters a risk of a generation shortage in real-time operations, it has numerous additional tools that it can deploy in a stepwise fashion to help ensure supply is adequate to meet demand.[7] The impact of many of these steps is not fully accounted for in MISO's loss of load analysis, making that planning conservative.

Days in advance of expected extreme heat, cold, or other severe weather, MISO can issue an alert or declare Conservative System Operations, directing transmission and generating resources on planned outages to return to service and make other preparations.[8] NERC notes this step helped ensure resource adequacy in MISO last summer.[9] As noted below, NERC's "elevated risk" designation for MISO is based on the assumption that many generators are on outage, so by taking steps to reduce generator outages MISO can reduce that risk.

Next, MISO can progress to issuing a capacity warning, which activates numerous additional steps to increase supply, including activating emergency pricing, and curtailing non-firm exports.[10] If the event then progresses to step 1a, MISO activates demand response resources, which are customers that are compensated for reducing their demand during periods of need. If an event progresses to step 1b, generating units are directed to operate at their

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[6] Potomac Economics, 2023 State of the Market Report for the MISO Electricity Markets, (June 2024) available at https://www.potomaceconomics.com/wp-content/uploads/2024/06/2023-MISO-SOM_Report_Body-Final.pdf, at 8-9.
[7] MISO, *MISO Market Capacity Emergency*, available at https://cdn.misoenergy.org/SO-P-EOP-11-002%20Rev%2021%20MISO%20Market%20Capacity%20Emergency683501.pdf, at 37-39.
[8] MISO, *Conservative System Operations*, available at https://cdn.misoenergy.org/SO-P-NOP-00-449%20Rev%2010%20Conservative%20System%20Operations688847.pdf
[9] NERC, *2025 Summer Reliability Assessment*, (May 2025) available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf, at 51, referring to summer 2024: "MISO experienced peak electricity demand during late August. Demand was between the normal and 90/10 summer peak forecast levels. Wind and solar resource output at the time of peak demand were near expectations for summer on-peak contributions. Forced outages of thermal units, however, were lower than expected. On the day prior to MISO's peak demand, operators issued advisories to maximize generation. Similar advisories were issued earlier in the summer, coinciding with above-normal temperatures and periods of high generator forced outages."
[10] MISO, *MISO Market Capacity Emergency*, available at https://cdn.misoenergy.org/SO-P-EOP-11-002%20Rev%2021%20MISO%20Market%20Capacity%20Emergency683501.pdf, at 10-12.

emergency maximum limits. If the event escalates further, MISO can then progress through additional steps including activating additional tiers of demand response resources, issuing public conservation requests, procuring emergency energy, and directing resources with environmental de-rates to request waivers, all before load is shed.[11]

C. NERC

Pursuant to Section 215 of the Federal Power Act, FERC certified NERC as the Electric Reliability Organization responsible for developing mandatory reliability standards, subject to FERC's review and approval. NERC also annually assesses seasonal and long-term reliability of the bulk power system and monitors system performance.

1. Mandatory Reliability Standards

NERC Regional Entity RFC has imposed a mandatory standard for Planning Resource Adequacy Analysis, Assessment, and Documentation for the region that includes Michigan. As the Planning Coordinator for Michigan, MISO is required to annually calculate the planning reserve margin required to meet the one day in ten years benchmark.[12] The standard also requires certain methods for the load forecast and the capacity accreditation for resources and imports.

Like other NERC and Regional Entity standards, this requirement is enforceable with fines of up to $1 million per day per violation. This further ensures MISO conducts robust and standardized resource adequacy planning, and each year MISO extensively documents that its planning methods fully meet this standard.[13]

2. Reliability Assessments

NERC also conducts periodic assessments of reliability in the country, including a summer, winter, and long-term reliability assessment every year. In the seasonal assessments, NERC groups regions into three categories for risk of resource adequacy shortfalls, as shown in the NERC figure below.[14] MISO's categorization as "elevated" risk in this year's NERC Summer Reliability Assessment is the middle of three risk categories, below "high" and above

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[11] *Id.* at 38-39.
[12] NERC, *Standard BAL-502-RFC-02*, available at https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-502-RFC-02.pdf
[13] *See, e.g.,* MISO, *Planning Year 2025-2026 Loss of Load Expectation Study Report*, available at https://cdn.misoenergy.org/PY%202025-2026%20LOLE%20Study%20Report685316.pdf?v=20250313114401, at 56-60.
[14] NERC, *2025 Summer Reliability Assessment*, (May 2025) available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf, at 10.

"normal." In its 2023[15] and 2024[16] Summer Reliability Assessments, NERC respectively identified 8 and 5 out of 13 U.S. regions as having elevated risk. Despite half of U.S. regions being designated as having elevated risk, there were no resource adequacy shortfalls in either summer.

Table 1: Seasonal Risk Assessment Summary

Category	Criteria[1]
High Potential for insufficient operating reserves in normal peak conditions	• Planning Reserve Margins do not meet Reference Margin Levels; or • Probabilistic indices exceed benchmarks (e.g., 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 scenarios[2]**
Elevated Potential for insufficient operating reserves in above-normal conditions	• Probabilistic indices are low but not negligible (e.g., LOLH above 0.1 hours over the season); 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 scenarios[4]

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

Figure 1: NERC table showing categories used for regions' seasonal risk

III. There Is No Evidence Consumers Energy, Michigan, or MISO Has a Resource Adequacy Emergency this Summer.

Michigan utility regulators and Consumers Energy have determined that Campbell was not needed to meet resource adequacy needs, a conclusion confirmed by MISO's resource adequacy analysis and capacity market results showing a capacity surplus for this summer. Moreover, NERC's Summer Reliability Assessment does not indicate MISO has a supply emergency.

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[15] NERC, *2023 Summer Reliability Assessment*, (May 2023) available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2023.pdf, at 6.
[16] NERC, *2024 Summer Reliability Assessment*, (May 2024) available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2024.pdf, at 6.

A. Michigan

Consumers Energy completed comprehensive reliability and economic modeling in its 2021 IRP, overseen by the Michigan Public Service Commission with robust engagement from stakeholders. As explained above, a cornerstone of this and all IRPs is ensuring resource adequacy needs are met. The utility,[17] the Commission,[18] and other stakeholders concluded that it was more economic and reliable to replace Campbell with a variety of other resources, including by (1) acquiring the nearby 1,200 MW gas-fired Covert Generating Station, which Consumers Energy subsequently purchased in May 2023, and (2) adding nearly 1,600 MW of demand response and energy efficiency by 2025.[19]

Michigan utilities are also bound by the state's Public Act 341 of 2016, which requires them to demonstrate to the Michigan Public Service Commission that they have sufficient generating capacity to meet their capacity obligations. The Commission can impose a state reliability mechanism capacity charge on utilities that fail to meet that requirement. In June 2022, the Commission approved Consumers Energy's demonstration for the 2025/2026 planning year,[20] and more recently Consumers successfully made this demonstration for the 2027/2028 planning year[21] and filed its demonstration for 2028/2029.[22]

Confirming that state and regional officials stand by their determination that the Campbell plant is not needed, the Chair of the Michigan Public Service Commission recently indicated that MISO, Michigan, and Consumers Energy did not ask to keep the Campbell plant online.[23]

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[17] CMS Energy, *Integrated Resource Plan*, (June 2021) available at https://s26.q4cdn.com/888045447/files/doc_presentations/2021/06/2021-Integrated-Resource-Plan.pdf

[18] Michigan Public Service Commission, *Exhibit A: Settlement Agreement*, https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000003KjSDAA0 (beginning at page 98 in the pdf)

[19] *Id.* at 4 (101 in the pdf).

[20] See the discussion of Case No. U-21099 at Michigan Public Service Commission, *MPSC approves Consumers Energy integrated resource plan settlement agreement, takes additional steps to boost electric capacity*, (June 2022) available at https://www.michigan.gov/mpsc/commission/news-releases/2022/06/23/mpsc-approves-consumers-irp_takes-steps-improve-capacity

[21] Michigan Public Service Commission, *Order*, Case Nos. U-21393 and U-21775, (August 2024) available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs000005gPyUAAU

[22] Consumers Energy, *Redacted Version of Consumers Energy Company's Capacity Demonstration for Planning Year 2028/2029*, (February 2025) available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00000bz8crAAA

[23] C. Brown and H. Stevens, *Coal and Gas Plants Were Closing. Then Trump Ordered Them to Keep Running*, (June 2025) available at https://www.nytimes.com/2025/06/06/climate/trump-coal-gas-plants-energy-emergency.html

B. MISO

Based on the loss of load analysis discussed above, MISO has concluded that it has "surplus capacity" for this summer, without Campbell.[24] The 2025/26 capacity auction yielded summer capacity supplies 2,623 MW or 2.2 percentage points above the summer reserve margin target of 7.9%, which was calibrated to meet the one day in ten years loss of load benchmark.[25] In other words, MISO would still meet this stringent reliability benchmark this summer even if an additional 2,623 MW of additional capacity unexpectedly were unavailable, and retaining Campbell would only increase MISO's already-generous capacity surplus for this summer beyond 4 GW. As noted above, capacity supply above the reserve margin target provides diminishing marginal returns.

The zonal results from MISO's 2025/26 capacity auction also confirm there is no resource adequacy shortfall this summer in Zone 7, which is the MISO footprint in Michigan's Lower Peninsula. Zone 7 has 1.2 GW of supplies above the summer Local Clearing Requirement, which is the amount of capacity that MISO has concluded must come from within Zone 7 after accounting for transmission constraints.[26]

C. NERC's Summer Reliability Assessment Does Not Indicate a Supply Emergency.

The NERC Summer Reliability Assessment that DOE cites in an attempt to justify the Campbell 202(c) order is based on information reported by MISO and other regional grid operators. Thus, the NERC assessment does not contradict MISO's conclusion that it has a capacity surplus above what it needs to meet its reliability target. In fact, NERC notes that for MISO, "Expectations for load loss and unserved energy are less than these amounts because MISO's resources are above the Reference Margin Level," which is MISO's reserve margin target calibrated to achieve a loss of load risk of one day in 10 years.[27]

NERC including MISO in the "elevated" summer risk category does not indicate a supply emergency. This year's Summer Reliability Assessment identifies four U.S. regions as having elevated risk, plus one region each in Canada and Mexico. As noted above, across the 2023 and 2024 Summer Reliability Assessments NERC identified half of U.S. regions as having elevated risk, yet there were no resource adequacy shortfalls in either summer.

This year's Summer Reliability Assessment finds that MISO has a 24.7% reserve margin, which NERC calculates corresponds to a 9.3% reserve margin with typical generator outage

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[24] MISO, *Planning Resource Auction Results for Planning Year 2025-26 (Corrections, reposted 05/29/25)*, available at https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf at 4.
[25] *Id.* at 3, 4, 37.
[26] *Id.* at 18.
[27] NERC, *2025 Summer Reliability Assessment*, (May 2025) available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf, at 12.

rates. NERC's finding of elevated risk only indicates a "Potential for insufficient operating reserves in above-normal conditions."[28] NERC finds that MISO would only see a generation shortfall with a perfect storm of 90th percentile demand (*i.e.*, demand is higher than expected in 9 out of 10 years) at the same time that MISO sees its highest historical rate for generator outages and derates due to "extreme conditions," and even in that worst case scenario it would only have a 1.9% shortfall.[29] By way of comparison, NERC's 2023 and 2024 Summer Reliability Assessments projected MISO would have a 6.9% and 6.3% shortfall under that worst case scenario, respectively, yet NERC still did not designate the risk as "high," and MISO ultimately had more than adequate supplies in both summers.

As explained above, MISO and utility reserve margins are already designed to accommodate wide interannual variability in electricity demand and generator outages, and MISO has calibrated its summer reserve margin to the stringent requirement that it only experience one day of shortfall in 10 years. Moreover, NERC notes that Michigan and the rest of MISO have the lowest risk of any region for seeing above average temperatures this summer.[30]

D. The NERC and MISO resource adequacy studies are likely conservative.

NERC's Summer Reliability Assessment and MISO's loss of load analysis both use conservative assumptions for the availability of imports and renewable output in MISO.

NERC's analysis does not fully account for MISO's ability to import power during periods of need, even though MISO successfully tapped into the supply and demand diversity provided by its neighbors to import more than 13 GW during Winter Storm Uri[31] and 4.5 GW during Winter Storm Elliott.[32] Other studies have documented significant diversity between MISO and its neighbors in the timing of peak demand, lulls in renewable output, and correlated thermal generator outage and derate events, including summer heat waves.[33] These geographic diversity benefits are due to inherent climate and weather diversity, and the fact that extreme heat and cold events are only at their most severe in small geographic areas that move over the course of an event.

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[28] *Id.* at 6.
[29] *Id.* at 10, 16.
[30] *Id.* at 9.
[31] M. Goggin, *Transmission Makes the Power System Resilient to Extreme Weather*, (July 2021) available at https://gridstrategiesllc.com/wp-content/uploads/2024/05/transmission-makes-the-power-system-resilient-to-extreme-weather.pdf, at 7.
[32] M. Goggin and Z. Zimmerman, *The Value of Transmission During Winter Storm Elliott*, (February 2023) available at https://acore.org/wp-content/uploads/2023/02/The-Value-of-Transmission-During-Winter-Storm-Elliott-ACORE.pdf
[33] A. Brooks, A. Silverstein, and R. Gramlich, *Resource Adequacy Value of Interregional Transmission*, (June 2025) available at https://gridstrategiesllc.com/wp-content/uploads/GridStrategies_RAValueInterregionalTx_250601.pdf; M. Goggin, Z. Zimmerman, and A. Sherman, *Quantifying a Minimum Interregional Transfer Capability Requirement*, (May 2023) available at https://gridstrategiesllc.com/wp-content/uploads/2023/05/GS_Interregional-Transfer-Requirement-Analysis-final54.pdf

DOE's National Transmission Planning Study documented the geographic diversity phenomenon with a compelling set of maps.[34] Those maps show that during the event when MISO saw the highest demand in the period 2007-2013, the Southwest Power Pool and the Southeast had significantly lower demand. Similar maps in the study show significant diversity in when MISO and its neighbors experience lulls in wind or solar output.[35]

NERC has previously noted that "MISO benefits from significant transfer capacity with neighboring assessment areas…"[36] Data in NERC's 2025 Summer Reliability Assessment documents that these neighboring grid operators have large reserve margin surpluses this summer, which further increases the availability of imports from those regions. NERC projects the summer reserve margin surplus under typical generator outage rates for the Southwest Power Pool at 18.2%, Ontario at 23.4%, PJM at 15.0%, the SERC Central region at 12.7%, and Manitoba at 11.2%.[37] As a result, at least some of those regions are highly likely to have surplus generating resources if MISO experiences periods of high demand or low supply this summer.

When calculating the reserve margin needed to meet the 1 day in 10 year target, MISO's loss of load study also makes conservative assumptions for the availability of imports from other regions. While MISO conducts robust statistical modeling of historical import availability, this analysis is conservative because hours in which MISO was exporting or minimally importing due to a lack of need are included in the dataset, even though MISO likely could have imported or at least reduced exports in those hours if needed.[38]

If there were a true resource adequacy emergency in MISO, a potential solution would be to issue a Section 202(c) order to facilitate interchange with neighboring grid operators. As the MISO independent market monitor[39] and others[40] have documented, inefficient pricing of market transactions along MISO's seams with neighboring grid operators can interfere with the efficient flow of power during shortage events. DOE could work with MISO and other stakeholders to improve the efficient flow of power across MISO's seams, improving the availability of imports during periods of peak need.

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[34] DOE, *National Transmission Planning Study: Chapter 2*, (October 2024) available at https://www.energy.gov/sites/default/files/2024-10/NationalTransmissionPlanningStudy-Chapter2.pdf, at 53.
[35] *Id.* at 51 and 52.
[36] NERC, *2024 Long Term Reliability Assessment*, (December 2024) available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf, at 44.
[37] NERC, *2025 Summer Reliability Assessment*, (May 2025) available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf, at 10.
[38] MISO, *Planning Year 2025-2026 Loss of Load Expectation Study Report*, available at https://cdn.misoenergy.org/PY%202025-2026%20LOLE%20Study%20Report685316.pdf?v=20250313114401, at 33.
[39] Potomac Economics, *2023 State of the Market Report*, (June 2024) available at https://cdn.misoenergy.org/2023%20State%20of%20the%20Market%20Report636641.pdf, at xiv-xv.
[40] J. Pfeifenberger and N. Bay, *Intertie Optimization: Efficient Use of Interregional Transmission (Update)*, (April 2024) available at https://www.brattle.com/wp-content/uploads/2024/04/Intertie-Optimization-Efficient-Use-of-Interregional-Transmission-Update.pdf

If DOE's claim of resource adequacy risk in MISO were true, facilitating interchange with neighboring grid operators would be more appropriately tailored to address the risk. This is because loss of load probability is concentrated into a narrow slice of hours on a small number of days when high demand coincides with low supply. Increased interchange can occur during just those hours, tapping into diversity in the timing of peak need between MISO and its neighbors. In contrast, retaining the Campbell coal plant for the entire summer is not well-tailored for meeting DOE's claimed emergency.[41]

MISO and NERC also appear not to have accounted for the fact that low wind speed events are negatively correlated with low solar output events. For example, wind speeds tend to be low during high pressure heat dome events, which tend to cause high solar output because there are fewer clouds during such events. Conversely, stormy conditions that result in reduced solar output due to clouds tend to be correlated with high wind output. As NERC notes, MISO has over 31 GW of wind and 18 GW of solar, so one resource can make up for shortfalls of the other.[42] As noted above, there is also significant diversity in when MISO and its neighboring regions experience lulls in renewable output. MISO meteorologists have also "projected normal to above-normal wind generation" for this summer.[43]

IV. Consumers Energy May Need to Buy Coal to Comply with DOE's Order.

The DOE data shown below indicate that coal supplies at the plant appear to have been drawn down in advance of its anticipated retirement, with enough coal remaining onsite as of the end of March 2025 to operate the plant for only about two to three weeks.[44] The DOE data indicate the plant is supplied via rail deliveries from a coal mine in Wyoming.[45]

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[41] As DOE's Campbell order notes, "FPA section 202(c) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts." U.S. 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, at 2.

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

[43] MISO, *2025 Summer Readiness Workshop*, (May 2025) available at https://cdn.misoenergy.org/20250508%20Summer%20Readiness%20Workshop%20Items%2002-04%20Presentation695282.pdf, at 17.

[44] DOE Energy Information Administration, *EIA-923 March 2025*, (May 2025) available at https://www.eia.gov/electricity/data/eia923/, with monthly stocks calculated by taking coal stock data as of December 2023 and then subtracting monthly consumption and adding monthly deliveries.

[45] *Id.*

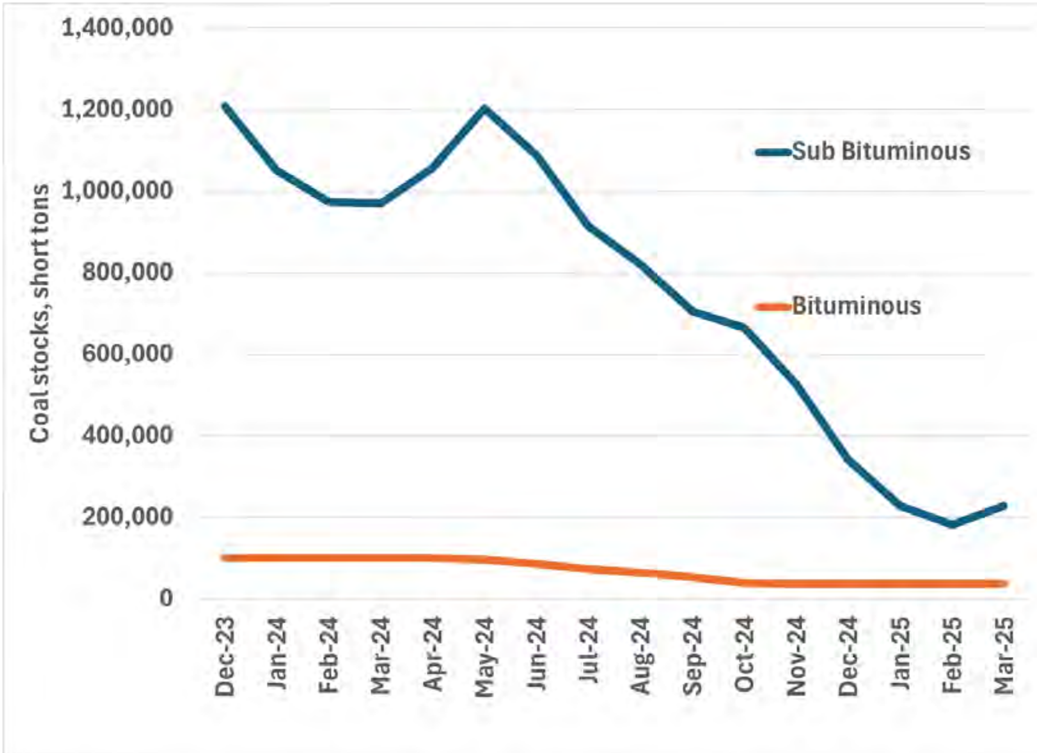

Figure 2: Coal supplies at Campbell, per DOE data

V. Qualifications of Michael Goggin

Michael Goggin has worked on electricity market and reliability issues for over 20 years. At Grid Strategies he serves as an expert on those topics for a range of clients including state utility regulators, grid operators, and non-profit organizations. He has testified as an expert in dozens of proceedings before state utility commissions in Arizona, Colorado, Georgia, Iowa, Illinois, Indiana, Wisconsin, Louisiana, Michigan, Minnesota, Missouri, Montana, Nevada, New Mexico, North Carolina, Ohio, Oklahoma, South Carolina, Virginia, Washington, and Wisconsin, as well as before FERC.

For the preceding ten years Michael worked at the American Wind Energy Association (now known as the American Clean Power Association), where he provided technical analysis regarding renewable energy, transmission, and wholesale electricity markets, including directing the organization's research and analysis team from 2014-2018. Prior to the American Wind Energy Association, he worked at a firm serving as a consultant to DOE, and at two environmental groups.

In the course of that work, Michael has co-authored more than one hundred filings to FERC; served as a technical reviewer for over a dozen national laboratory reports, academic articles, and renewable integration studies; published academic articles and conference presentations on renewable integration, transmission, and policy; and been elected to the Standards, Operating, and Planning Committees of NERC. He graduated with honors from Harvard University. His recent publications are available at https://gridstrategiesllc.com/reports/.

VI. Sources

The principal documents I relied on in preparing this report include the materials listed below and in footnotes. To the extent feasible, relevant documents are included in the Appendix of the Request for Rehearing.

-MISO, *Planning Year 2025-2026 Loss of Load Expectation Study Report*, available at https://cdn.misoenergy.org/PY%202025-2026%20LOLE%20Study%20Report685316.pdf?v=20250313114401

-MISO, *Planning Resource Auction Results for Planning Year 2025-26 (Corrections, reposted 05/29/25)*, available at https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf

-MISO, *MISO Market Capacity Emergency*, available at https://cdn.misoenergy.org/SO-P-EOP-11-002%20Rev%2021%20MISO%20Market%20Capacity%20Emergency683501.pdf

-U.S. EPA, *Continuous Emission Monitoring Systems: Custom Data Download*, available at https://campd.epa.gov/data/custom-data-download

-NERC, *Standard BAL-502-RFC-02*, available at https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-502-RFC-02.pdf

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

-Michigan Public Service Commission, *Exhibit A: Settlement Agreement*, https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000003KjSDAA0 (beginning at page 98 in the pdf)

DOE Energy Information Administration, *EIA-923 March 2025*, (May 2025) available at https://www.eia.gov/electricity/data/eia923/

Michael Goggin
Vice President
Grid Strategies, LLC

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

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

Exhibit 11
NIPSCO 2025 Planning Reserve Margin Report

FILED
May 1, 2025
INDIANA UTILITY
REGULATORY COMMISSION

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 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.	)	**CAUSE NO. 46233**

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,

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CERTIFICATE OF SERVICE

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

Dated this 1st day of May, 2025.

Tiffany Murray

IC 8-1-8.5-13(i) Reporting Form - Planning Resource Year 1 (2025 to 2026)

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 *IC 8-1-8.5-13(i)(1) 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)** *IC 8-1-8.5-13(f) definition*	**Location:** *RTO interconnection zone*	**Fuel Source**	**Additional Comments**
CIN.SUCRKGT1	175	146.4	144.4	133.7	170.7	Zone 6	Gas	This is one combined asset.
CIN.SUCRKGT2	175	145.6	145.1	162.6	170.8	Zone 6	Gas	
CIN.SUCRKST1	228	202.4	192.1	181	223.1	Zone 6	Waste Heat	
NIPS.MICHCP12	469	313.4	311.5	170.9	317.6	Zone 6	Coal	
NIPS.NORWAPNOR	4	1.6	0.9	2.2	3.4	Zone 6	Water	
NIPS.OAKDAPOAK	6				4.6	Zone 6	Water	Planned outage until February 2026
NIPS.ROSEWRWF	100.1	20.2	25.7	23.8	26.8	Zone 6	Wind	This is a tax equity joint venture w/ NIPSCO as controlling member
NIPS.INCROSWF	300.1	55.5	46.8	67.3	62.8	Zone 6	Wind	This is a tax equity joint venture w/ NIPSCO as controlling member
NIPS.SCHAHP16A	78	44.3	58.6	35.4	39.7	Zone 6	Gas	
NIPS.SCHAHP16B	77	63.4	70.6	77.1	68.4	Zone 6	Gas	
NIPS.SCHAHP17	361	199.7	245.9			Zone 6	Coal	Plan to retire end of 2025
NIPS.SCHAHP18	361	295.6	271			Zone 6	Coal	Plan to retire end of 2025
NIPS.DUNNBR1SF	265	181.7	109.2	3.2	154.3	Zone 6	Solar	This is a tax equity joint venture w/ NIPSCO as controlling member.
NIPS.INCRMLSP	200	131.4	85.7	1.6	108.2	Zone 6	Solar	This is a tax equity joint venture w/ NIPSCO as controlling member.
Dunns II	435	217.5	217.5	21.8	217.5	Zone 6	Solar	
Dunns II Battery	56.25	53.5	53.5	53.5	53.5	Zone 6	Battery	
Fairbank	250	125	125	12.5	125	Zone 6	Solar	
Gibson	200		100	10	100	Zone 6	Solar	
Calvary	200	109	77.5	7.8	77.5	Zone 6	Solar	
Calvary Battery	45	45	42.8	42.8	42.8	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)** *IC 8-1-8.5-13(f) definition*	**Location:** *RTO interconnection zone*	**Fuel Source**	**Additional Comments**
[redacted]								
								Capacity from external resource zone
								Capacity from external resource zone
								Capacity from external resource zone
								Capacity from external resource zone
								Capacity from external resource zone
								Capacity from external resource zone
								Capacity from external resource zone

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 531 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	169.9	121.6	176.5	199.1	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 531 Tier 2 & 3 Customers Load Modiying Resource	Summer Registered As LMR @ MISO (ZRC) (MW X (1+PRM) X (1+TL))	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	198.9	176.3	164.0	209.0	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	84.0	86.8	89.1	Registered as LMR @ MISO by NIPSCO
E	0.0	0.0	0.0	0.0	Registered as LMR @ MISO by NIPSCO
F	152.0	170.6	186.4	189.5	Registered as LMR @ MISO by NIPSCO
G	185.9	198.9	186.2	229.8	Registered as LMR @ MISO by NIPSCO

		This minus Rate 531 Tier 2 & 3 Customers	This with Rate 531 Tier 2 & 3 Customers	Additional Comments
RTO established Planning Reserve Margin requirement *(see IC 8-1-8.5-13 (i)(4)*	Summer Demand ___ MWx(1+ % PRM ____) = ____MW	2600.1	3479.6	w/ TL of 2.5% PRMR of 7.9%

NIPSCO has peformed this calculation without Rate 531 Tier 2 and 3 customers (column D) and with those customers (column E)

Fall Demand ___ MWx(1+ % PRM ____) = ____MW	This minus Rate 531 Tier 2 & 3 Customers	This with Rate 531 Tier 2 & 3 Customers	Additional Comments
	2467.6	3408.6	w/ TL of 3.8% PRMR of 14.9%

Winter Demand ___ MWx(1+ % PRM ____) = ____MW	This minus Rate 531 Tier 2 & 3 Customers	This with Rate 531 Tier 2 & 3 Customers	Additional Comments
	1941.9	2897.5	w/ TL of 1.7% PRMR of 18.4%

Spring Demand ___ MWx(1+ % PRM ____) = ____MW	This minus Rate 531 Tier 2 & 3 Customers	This with Rate 531 Tier 2 & 3 Customers	Additional Comments
	2415.4	3472.2	w/ TL of 3.4% PRMR of 25.3%

Please describe any other federal reliability requirement:	

Reliability Adequacy Metrics *[defined in IC 8-1-8.5-13(e)]*			
Summer RA Metric *IC 8-1-8.5-13(e)(1)*	**Fall RA Metric** *IC 8-1-8.5-13(e)(2)*	**Winter RA Metric** *IC 8-1-8.5-13(e)(2)*	**Spring RA Metric** *IC 8-1-8.5-13(e)(2)*
Summer UCAP/PRM Requirement = _____%	Fall UCAP/PRM Requirement = _____%	Winter UCAP/PRM Requirement = _____%	Spring UCAP/PRM Requirement = _____%

NIPSCO has peformed this calculation (below) without Rate 531 Tier 2 and 3 customers (columns B and C) and with those customers (column D and E)

This minus Rate 531 Tier 2 & 3 Customers				This with Rate 531 Tier 2 & 3 Customers			
Summer UCAP	Fall UCAP	Winter UCAP	Spring UCAP	Summer UCAP	Fall UCAP	Winter UCAP	Spring UCAP
[redacted]							
Summer RA Metric	Fall RA Metric	Winter RA Metric	Spring RA Metric	Summer RA Metric	Fall RA Metric	Winter RA Metric	Spring RA Metric
[redacted]							

IC 8-1-8.5-13(i) Reporting Form - Planning Resource Year 2 (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 *IC 8-1-8.5-13(i)(1) 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)** *IC 8-1-8.5-13(f) definition*	**Location:** *RTO interconnection zone*	**Fuel Source**	**Additional Comments**
CIN.SUCRKGT1	175	146.4	144.4	133.7	170.7	Zone 6	Gas	This is one combined asset.
CIN.SUCRKGT2	175	145.6	145.1	162.6	170.8	Zone 6	Gas	
CIN.SUCRKST1	228	202.4	192.1	181	223.1	Zone 6	Waste Heat	
NIPS.MICHCP12	469	313.4	311.5	170.9	317.6	Zone 6	Coal	
NIPS.NORWAPNOR	4	1.6	0.9	2.2	3.4	Zone 6	Water	
NIPS.OAKDAPOAK	6	1.4	0	2.3	4.6	Zone 6	Water	
NIPS.ROSEWRWF	100.1	20.2	25.7	23.8	26.8	Zone 6	Wind	This is a tax equity joint venture w/ NIPSCO as controlling member
NIPS.INCROSWF	300.1	55.5	46.8	67.3	62.8	Zone 6	Wind	This is a tax equity joint venture w/ NIPSCO as controlling member
NIPS.SCHAHP16A	78	44.3	58.6	35.4	39.7	Zone 6	Gas	
NIPS.SCHAHP16B	77	63.4	70.6	77.1	68.4	Zone 6	Gas	
NIPS.DUNNBR1SF	265	181.7	109.2	3.2	154.3	Zone 6	Solar	This is a tax equity joint venture w/ NIPSCO as controlling member.
NIPS.INCRMLSP	200	131.4	85.7	1.6	108.2	Zone 6	Solar	This is a tax equity joint venture w/ NIPSCO as controlling member.
Dunns II	435	217.5	217.5	21.8	217.5	Zone 6	Solar	
Dunns II Battery	56.25	53.5	53.5	53.5	53.5	Zone 6	Battery	
Fairbank	250	125	125	12.5	125	Zone 6	Solar	
Gibson	200	100	100	10	100	Zone 6	Solar	
Calvary	200	109	77.5	7.8	77.5	Zone 6	Solar	
Calvary Battery	45	45	42.8	42.8	42.8	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)** *IC 8-1-8.5-13(f) definition*	**Location:** *RTO interconnection zone*	**Fuel Source**	**Additional Comments**
[redacted]								
								Capacity from external resource zone
								Capacity from external resource zone
								Capacity from external resource zone

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 531 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	169.9	121.6	176.5	199.1	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 531 Tier 2 & 3 Customers Load Modiying Resource	Summer Registered As LMR @ MISO (ZRC) (MW X (1+PRM) X (1+TL))	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	198.9	176.3	164.0	209.0	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	84.0	86.8	89.1	Registered as LMR @ MISO by NIPSCO
E	0.0	0.0	0.0	0.0	Registered as LMR @ MISO by NIPSCO
F	152.0	170.6	186.4	189.5	Registered as LMR @ MISO by NIPSCO
G	185.9	198.9	186.2	229.8	Registered as LMR @ MISO by NIPSCO

		This minus Rate 531 Tier 2 & 3 Customers	This with Rate 531 Tier 2 & 3 Customers	Additional Comments
RTO established Planning Reserve Margin requirement *(see IC 8-1-8.5-13 (i)(4)*	Summer Demand ___ MWx(1+ % PRM ____) = ____MW	2600.8	3480.4	w/ TL of 2.5% PRMR of 7.9%

NIPSCO has peformed this calculation without Rate 531 Tier 2 and 3 customers (column D) and with those customers (column E)

	This minus Rate 531 Tier 2 & 3 Customers	This with Rate 531 Tier 2 & 3 Customers	Additional Comments
Fall Demand ___ MWx(1+ % PRM ____) = ____MW	2468.1	3409.1	w/ TL of 3.8% PRMR of 14.9%

	This minus Rate 531 Tier 2 & 3 Customers	This with Rate 531 Tier 2 & 3 Customers	Additional Comments
Winter Demand ___ MWx(1+ % PRM ____) = ____MW	1942	2897.6	w/ TL of 1.7% PRMR of 18.4%

	This minus Rate 531 Tier 2 & 3 Customers	This with Rate 531 Tier 2 & 3 Customers	Additional Comments
Spring Demand ___ MWx(1+ % PRM ____) = ____MW	2415.3	3472.1	w/ TL of 3.4% PRMR of 25.3%

Please describe any other federal reliability requirement:	

Reliability Adequacy Metrics *[defined in IC 8-1-8.5-13(e)]*			
Summer RA Metric *IC 8-1-8.5-13(e)(1)*	**Fall RA Metric** *IC 8-1-8.5-13(e)(2)*	**Winter RA Metric** *IC 8-1-8.5-13(e)(2)*	**Spring RA Metric** *IC 8-1-8.5-13(e)(2)*
Summer UCAP/PRM Requirement = _____%	Fall UCAP/PRM Requirement = _____%	Winter UCAP/PRM Requirement = _____%	Spring UCAP/PRM Requirement = _____%

NIPSCO has peformed this calculation (below) without Rate 531 Tier 2 and 3 customers (columns B and C) and with those customers (column D and E)

This minus Rate 531 Tier 2 & 3 Customers				This with Rate 531 Tier 2 & 3 Customers			
Summer UCAP	Fall UCAP	Winter UCAP	Spring UCAP	Summer UCAP	Fall UCAP	Winter UCAP	Spring UCAP
[redacted]							
Summer RA Metric	Fall RA Metric	Winter RA Metric	Spring RA Metric	Summer RA Metric	Fall RA Metric	Winter RA Metric	Spring RA Metric
[redacted]							

IC 8-1-8.5-13(i) Reporting Form - Planning Resource Year 3 (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 *IC 8-1-8.5-13(i)(1) 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)** *IC 8-1-8.5-13(f) definition*	**Location:** *RTO interconnection zone*	**Fuel Source**	**Additional Comments**
CIN.SUCRKGT1	175	146.4	144.4	133.7	170.7	Zone 6	Gas	
CIN.SUCRKGT2	175	145.6	145.1	162.6	170.8	Zone 6	Gas	This is one combined asset.
CIN.SUCRKST1	228	202.4	192.1	181	223.1	Zone 6	Waste Heat	
NIPS.MICHCP12	469	313.4	311.5	170.9	317.6	Zone 6	Coal	
NIPS.NORWAPNOR	4	1.6	0.9	2.2	3.4	Zone 6	Water	
NIPS.OAKDAPOAK	6	1.4	0	2.3	4.6	Zone 6	Water	
NIPS.ROSEWRWF	100.1	20.2	25.7	23.8	26.8	Zone 6	Wind	This is a tax equity joint venture w/ NIPSCO as controlling member
NIPS.INCROSWF	300.1	55.5	46.8	67.3	62.8	Zone 6	Wind	This is a tax equity joint venture w/ NIPSCO as controlling member
NIPS.SCHAHP16A	78	44.3	58.6			Zone 6	Gas	Plan to retire end of 2027
NIPS.SCHAHP16B	77	63.4	70.6			Zone 6	Gas	Plan to retire end of 2027
NIPS.DUNNBR1SF	265	181.7	109.2	3.2	154.3	Zone 6	Solar	This is a tax equity joint venture w/ NIPSCO as controlling member.
NIPS.INCRMLSP	200	131.4	85.7	1.6	108.2	Zone 6	Solar	This is a tax equity joint venture w/ NIPSCO as controlling member.
Dunns II	435	217.5	217.5	21.8	217.5	Zone 6	Solar	
Dunns II Battery	56.25	53.5	53.5	53.5	53.5	Zone 6	Battery	
Fairbank	250	125	125	12.5	125	Zone 6	Solar	
Gibson	200	100	100	10	100	Zone 6	Solar	
Calvary	200	109	77.5	7.8	77.5	Zone 6	Solar	
Calvary Battery	45	45	42.8	42.8	42.8	Zone 6	Battery	
Templeton Wind	200	41.6	61.4	58	50.6	Zone 6	Wind	
Peaker	450			361.4	400.1	Zone 6	Gas	Approved Peaker

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)** *IC 8-1-8.5-13(f) definition*	**Location:** *RTO interconnection zone*	**Fuel Source**	**Additional Comments**
[redacted]								
								Capacity from external resource zone

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 531 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	169.9	121.6	176.5	199.1	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 531 Tier 2 & 3 Customers Load Modiying Resource	Summer Registered As LMR @ MISO (ZRC) (MW X (1+PRM) X (1+TL))	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	198.9	176.3	164.0	209.0	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	84.0	86.8	89.1	Registered as LMR @ MISO by NIPSCO
E	0.0	0.0	0.0	0.0	Registered as LMR @ MISO by NIPSCO
F	152.0	170.6	186.4	189.5	Registered as LMR @ MISO by NIPSCO
G	185.9	198.9	186.2	229.8	Registered as LMR @ MISO by NIPSCO

		This minus Rate 531 Tier 2 & 3 Customers	This with Rate 531 Tier 2 & 3 Customers	Additional Comments
RTO established Planning Reserve Margin requirement *(see IC 8-1-8.5-13 (i)(4)*	Summer Demand ___ MWx(1+ % PRM ____) = ____MW	2600.2	3479.8	w/ TL of 2.5% PRMR of 7.9%

NIPSCO has peformed this calculation without Rate 531 Tier 2 and 3 customers (column D) and with those customers (column E)

	This minus Rate 531 Tier 2 & 3 Customers	This with Rate 531 Tier 2 & 3 Customers	Additional Comments
Fall Demand ___ MWx(1+ % PRM ____) = ____MW	2467.4	3408.4	w/ TL of 3.8% PRMR of 14.9%

	This minus Rate 531 Tier 2 & 3 Customers	This with Rate 531 Tier 2 & 3 Customers	Additional Comments
Winter Demand ___ MWx(1+ % PRM ____) = ____MW	1942	2897.5	w/ TL of 1.7% PRMR of 18.4%

	This minus Rate 531 Tier 2 & 3 Customers	This with Rate 531 Tier 2 & 3 Customers	Additional Comments
Spring Demand ___ MWx(1+ % PRM ____) = ____MW	2414.8	3471.4	w/ TL of 3.4% PRMR of 25.3%

Please describe any other federal reliability requirement:	

Reliability Adequacy Metrics *[defined in IC 8-1-8.5-13(e)]*			
Summer RA Metric *IC 8-1-8.5-13(e)(1)*	**Fall RA Metric** *IC 8-1-8.5-13(e)(2)*	**Winter RA Metric** *IC 8-1-8.5-13(e)(2)*	**Spring RA Metric** *IC 8-1-8.5-13(e)(2)*
Summer UCAP/PRM Requirement = _____%	Fall UCAP/PRM Requirement = _____%	Winter UCAP/PRM Requirement = _____%	Spring UCAP/PRM Requirement = _____%

NIPSCO has peformed this calculation (below) without Rate 531 Tier 2 and 3 customers (columns B and C) and with those customers (column D and E)

This minus Rate 531 Tier 2 & 3 Customers				This with Rate 531 Tier 2 & 3 Customers			
Summer UCAP	Fall UCAP	Winter UCAP	Spring UCAP	Summer UCAP	Fall UCAP	Winter UCAP	Spring UCAP
[redacted]							
Summer RA Metric	Fall RA Metric	Winter RA Metric	Spring RA Metric	Summer RA Metric	Fall RA Metric	Winter RA Metric	Spring RA Metric
[redacted]							

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

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

Exhibit 12
CenterPoint 2025 Planning Reserve Margin Report

FILED
May 23, 2025
INDIANA UTILITY
REGULATORY COMMISSION

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. 46236**

**SUBMISSION OF CENTERPOINT ENERGY INDIANA SOUTH'S
2025 HEA 1520 REPORT**

In accordance with the Commission's May 22, 2025 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 2025 HEA 1520 Report.

(Signature Page Follows)

DATED: May 23, 2025

Respectfully submitted,
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 23, 2025, 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
Carol Drake
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Indianapolis, IN 46204
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Jeffery A. Earl Atty. No. 27821-64

IC 8-1-8.5-13(i) Reporting Form - Planning Resource Year 1 (2025 to 2026)

SAC Accreditation **CEI South**

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 *IC 8-1-8.5-13(i)(1) definition*	**ICAP (MW)** *Nameplate capacity*	**Summer Accredited Capacity (MW)** *IC 8-1-8.5-13(i) definition*	**Fall Accredited Capacity (MW)** *IC 8-1-8.5-13(d) definition*	**Winter Accredited Capacity (MW)** *IC 8-1-8.5-13(j) definition*	**Spring Accredited Capacity (MW)** *IC 8-1-8.5-13(h) definition*	**Location:** *RTO interconnection zone*	**Fuel Source**	**Additional Comments**
AB Brown 3	80	67	72	92	76	MISO Zone 6	Gas/Fuel Oil	Primary fuel is natural gas but can operate on fuel oil
AB Brown 4	80	71	67	89	80	MISO Zone 6	Gas	-
AB Brown 5	232	0	0	183	205	MISO Zone 6	Natural Gas	AB Brown 5 Capacity Accreditation was deferred until Winter 25/26 due to factory transformer testing. Capacity was purchased to supplement the gap due to the delay.
AB Brown 6	232	198	200	183	205	MISO Zone 6	Natural Gas	-
FB Culley 2	90	71	0	0	0	MISO Zone 6	Coal	The IMM approved a planned outage for FB Culley 2 in Fall 25 An Attachment Y was submitted to MISO for suspension of FB Culley 2 in December 2025. The IMM has approved an exemption for the suspension of FB Culley 2 in Winter 25 and Spring 25/26
FB Culley 3	270	181	0	232	120	MISO Zone 6	Coal	The IMM approved a planned outage for FB Culley 3 in Fall 25 The lower Spring Accredited Capacity reflects a capacity swap with another utility for capacity in the Fall season
OVEC (Ohio Valley Electric Corp.)	32	30	30	31	31	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 #88106335.
Troy Solar	50	33	25	1	29	MISO Zone 6	Solar	-
Posey Solar	191	96	96	10	96	MISO Zone 6	Solar	-
Oak Hill Solar	2	-	-	-	-	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	-	-	-	-	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	-	-	-	-	MISO Zone 6	Battery	Located on CEI South distribution system and accounted for in peak load forecast. Not a SAC resource.
Blackfoot Landfill	3	-	-	-	-	MISO Zone 6	Landfill Gas	Located on CEI South distribution system and accounted for in peak load forecast. Not a SAC resource.

Contracted Resource *IC 8-1-8.5-13(l)(2) definition*	**ICAP (MW)** *Nameplate capacity*	**Summer Accredited Capacity (MW)** *IC 8-1-8.5-13(i) definition*	**Fall Accredited Capacity (MW)** *IC 8-1-8.5-13(d) definition*	**Winter Accredited Capacity (MW)** *IC 8-1-8.5-13(j) definition*	**Spring Accredited Capacity (MW)** *IC 8-1-8.5-13(h) definition*	**Location:** *RTO interconnection zone*	**Fuel Source**	**Additional Comments**
Benton County Wind Farm	30	10	5	[redacted]	[redacted]	MISO Zone 6	Wind	-
Fowler Wind Farm	50	7	11	[redacted]	[redacted]	MISO Zone 6	Wind	-
Wheatland Solar	150	0	0	[redacted]	[redacted]	MISO Zone 6	Solar	-
Galesburg Wind	147	0	0	[redacted]	[redacted]	MISO Zone 4	Wind	-
Salt Creek	170	0	0	[redacted]	[redacted]	MISO Zone 3	Wind	Energy may be available starting December 2025, if PPA approved in Cause # 46218
Capacity Contracts	N/A	230	411.6	[redacted]	[redacted]	-	-	Individual capacity contract is confidential
Total Contracted Resources		247	428	170	170			

Demand Response Resource *IC 8-1-8.5-13(i)(3) definition*	**Summer Accredited Capacity (MW)** *IC 8-1-8.5-13(i) definition*	**Fall Accredited Capacity (MW)** *IC 8-1-8.5-13(d) definition*	**Winter Accredited Capacity (MW)** *IC 8-1-8.5-13(j) definition*	**Spring Accredited Capacity (MW)** *IC 8-1-8.5-13(h) definition*	**Additional Comments**
DR - DLC - Summer Cycler	5	0	0	0	Direct load control via switches on electric cooling units and electric water heaters. This DR is only available in summer months per CEI South tariff
DR - DLC - Thermostats	9	0	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

RTO established Planning Reserve Margin requirement *(see IC 8-1-8.5-13 (i)(4)*[1]	1182	1077	990	1016

Please describe any other federal reliability requirement:	-

Reliability Adequacy Metrics *[defined in IC 8-1-8.5-13(e)]*

Summer RA Metric	**Fall RA Metric**	**Winter RA Metric**	**Spring RA Metric**
85%	85%	100%	99%

1. CEI South PRMR as of March 25, 2025, as provided by MISO, and consistent with the prior 1520 reports

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

SAC Accreditation **CEI South**

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 *IC 8-1-8.5-13(l)(1) definition*	**ICAP (MW)** *Nameplate capacity*	**Summer Accredited Capacity (MW)** *IC 8-1-8.5-13(i) definition*	**Fall Accredited Capacity (MW)** *IC 8-1-8.5-13(d) definition*	**Winter Accredited Capacity (MW)** *IC 8-1-8.5-13(j) definition*	**Spring Accredited Capacity (MW)** *IC 8-1-8.5-13(h) definition*	**Location:** *RTO interconnection zone*	**Fuel Source**	**Additional Comments**
AB Brown 3	80	67	72	92	76	MISO Zone 6	Gas/Fuel Oil	Primary fuel is natural gas but can operate on fuel oil
AB Brown 4	80	71	67	89	80	MISO Zone 6	Gas	-
AB Brown 5	232	198	200	183	205	MISO Zone 6	Natural Gas	-
AB Brown 6	232	198	200	183	205	MISO Zone 6	Natural Gas	-
FB Culley 3	270	250	269	232	270	MISO Zone 6	Coal	-
OVEC (Ohio Valley Electric Corp.)	32	30	30	31	31	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 #88106335.
Troy Solar	50	33	25	1	29	MISO Zone 6	Solar	-
Posey Solar	191	96	96	10	96	MISO Zone 6	Solar	-
Future Wind	200	0	0	106	36	MISO Zone 4	Wind	-
Oak Hill Solar	2	-	-	-	-	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	-	-	-	-	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	-	-	-	-	MISO Zone 6	Battery	Located on CEI South distribution system and accounted for in peak load forecast. Not a SAC resource.
Blackfoot Landfill	3	-	-	-	-	MISO Zone 6	Landfill Gas	Located on CEI South distribution system and accounted for in peak load forecast. Not a SAC resource.

Contracted Resource [1] *IC 8-1-8.5-13(l)(2) definition*	**ICAP (MW)** *Nameplate capacity*	**Summer Accredited Capacity (MW)** *IC 8-1-8.5-13(i) definition*	**Fall Accredited Capacity (MW)** *IC 8-1-8.5-13(d) definition*	**Winter Accredited Capacity (MW)** *IC 8-1-8.5-13(j) definition*	**Spring Accredited Capacity (MW)** *IC 8-1-8.5-13(h) definition*	**Location:** *RTO interconnection zone*	**Fuel Source**	**Additional Comments**
Benton County Wind Farm	30	[redacted]				MISO Zone 6	Wind	-
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Wheatland Solar	150					MISO Zone 6	Solar	-
Galesburg Wind	147					MISO Zone 4	Wind	-
Vermillion Rise Solar	185					MISO Zone 6	Solar	Energy may be available starting December 2025, if PPA approved in Cause # 46218
Salt Creek Wind	170					MISO Zone 3	Wind	
Capacity Contracts	N/A					-	-	Individual capacity contract is confidential
Total Contracted Resources		299	291	346	302			

Demand Response Resource *IC 8-1-8.5-13(l)(3) definition*	**Summer Accredited Capacity (MW)** *IC 8-1-8.5-13(i) definition*	**Fall Accredited Capacity (MW)** *IC 8-1-8.5-13(d) definition*	**Winter Accredited Capacity (MW)** *IC 8-1-8.5-13(j) definition*	**Spring Accredited Capacity (MW)** *IC 8-1-8.5-13(h) definition*	**Additional Comments**
DR - DLC - Summer Cycler	7	0	0	0	Direct load control via switches on electric cooling units and electric water heaters. This DR is only available in summer months per CEI South tariff
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RTO established Planning Reserve Margin requirement [2] *(see IC 8-1-8.5-13 (i)(4)*	1184	1152	990	1019

Please describe any other federal reliability requirement:	-

Reliability Adequacy Metrics *[defined in IC 8-1-8.5-13(e)]*

Summer RA Metric	**Fall RA Metric**	**Winter RA Metric**	**Spring RA Metric**
106%	109%	129%	130%

1. SIGE received termination letter for Rustic Hills project after the MISO OMS Survey submittal due date; Rustic Hills was removed from the 1520 and will be removed in future OMS Survey
2. CEI South PRMR as of March 25, 2025, as provided by MISO, and consistent with the prior 1520 report

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

SAC Accreditation **CEI South**

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 *IC 8-1-8.5-13(l)(1) definition*	**ICAP (MW)** *Nameplate capacity*	**Summer Accredited Capacity (MW)** *IC 8-1-8.5-13(i) definition*	**Fall Accredited Capacity (MW)** *IC 8-1-8.5-13(d) definition*	**Winter Accredited Capacity (MW)** *IC 8-1-8.5-13(j) definition*	**Spring Accredited Capacity (MW)** *IC 8-1-8.5-13(h) definition*	**Location:** *RTO interconnection zone*	**Fuel Source**	**Additional Comments**
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AB Brown 6	232	198	200	183	205	MISO Zone 6	Natural Gas	-
FB Culley 3	270	267	267	267	268	MISO Zone 6	Coal	-
OVEC (Ohio Valley Electric Corp.)	32	30	30	31	31	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 #88106335.
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Contracted Resource [1] *IC 8-1-8.5-13(l)(2) definition*	**ICAP (MW)** *Nameplate capacity*	**Summer Accredited Capacity (MW)** *IC 8-1-8.5-13(i) definition*	**Fall Accredited Capacity (MW)** *IC 8-1-8.5-13(d) definition*	**Winter Accredited Capacity (MW)** *IC 8-1-8.5-13(j) definition*	**Spring Accredited Capacity (MW)** *IC 8-1-8.5-13(h) definition*	**Location:** *RTO interconnection zone*	**Fuel Source**	**Additional Comments**
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Vermillion Rise Solar	185					MISO Zone 6	Solar	Energy may be available starting December 2025, if PPA approved in Cause # 46218
Salt Creek Wind	170					MISO Zone 3	Wind	-
Capacity Contracts	N/A					-	-	Individual capacity contract is confidential
Total Contracted Resources		299	291	346	394			

Demand Response Resource *IC 8-1-8.5-13(l)(3) definition*	**Summer Accredited Capacity (MW)** *IC 8-1-8.5-13(i) definition*	**Fall Accredited Capacity (MW)** *IC 8-1-8.5-13(d) definition*	**Winter Accredited Capacity (MW)** *IC 8-1-8.5-13(j) definition*	**Spring Accredited Capacity (MW)** *IC 8-1-8.5-13(h) definition*	**Additional Comments**
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RTO established Planning Reserve Margin requirement[2] *(see IC 8-1-8.5-13 (i)(4)*	1187	1116	992	1069

Please describe any other federal reliability requirement:	-

Reliability Adequacy Metrics *(defined in IC 8-1-8.5-13(e))*

Summer RA Metric	**Fall RA Metric**	**Winter RA Metric**	**Spring RA Metric**
111%	115%	132%	133%

1. SIGE received termination letter for Rustic Hills project after the MISO OMS Survey submittal due date; Rustic Hills was removed from the 1520 and will be removed in future OMS Survey.
2. CEI South PRMR as of March 25, 2025, as provided by MISO, and consistent with the prior 1520 reports

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

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

Exhibit 13
NIPSCO Performance Metric
Collaborative Update

FILED
July 1, 2025
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE AND FOR APPROVAL OF: (1) CHANGES TO ITS ELECTRIC SERVICE TARIFF INCLUDING A NEW SCHEDULE OF RATES AND CHARGES AND CHANGES TO THE GENERAL RULES AND REGULATIONS AND CERTAIN RIDERS; (2) REVISED DEPRECIATION ACCRUAL RATES; (3) INCLUSION IN ITS BASIC RATES AND CHARGES OF THE COSTS ASSOCIATED WITH CERTAIN PREVIOUSLY APPROVED QUALIFIED POLLUTION CONTROL PROPERTY, CLEAN COAL TECHNOLOGY, CLEAN ENERGY PROJECTS AND FEDERALLY MANDATED COMPLIANCE PROJECTS; AND (4) ACCOUNTING RELIEF TO ALLOW NIPSCO TO DEFER, AS A REGULATORY ASSET OR LIABILITY, CERTAIN COSTS FOR RECOVERY IN A FUTURE PROCEEDING.	)	**CAUSE NO. 44688**

COMPLIANCE FILING
PERFORMANCE METRIC COLLABORATIVE UPDATE

Ordering Paragraph 10 of the Indiana Utility Regulatory Commission's July 18, 2016 Order issued in this Cause ("Rate Case Order") directed Northern Indiana Public Service Company LLC ("NIPSCO") to participate in a collaborative for the purpose of implementing performance metrics. The Commission ordered that

NIPSCO shall keep the Commission apprised of the progress of the collaborative through compliance filings made under this Cause as described in its Order as follows:

> [W]e find that NIPSCO shall facilitate a meeting with interested stakeholders within six weeks of the effective date of the Order in this Cause to collaborate on a path for moving forward with a performance metrics initiative.
>
> * * *
>
> In order that the Commission and interested stakeholders may stay abreast of the collaborative process, we direct NIPSCO to make a progress update filing with the Commission within 90 days of the initial meeting of the collaborative. We also order NIPSCO to file quarterly reports for the first year and an annual report by July 1, 2017, and for each year thereafter until otherwise indicated by the Presiding Officers.

Attached please find NIPSCO's Performance Metric Collaborative Report dated July 1, 2025, which incorporates revisions and language as provided by the interested stakeholders participating in NIPSCO's Performance Metrics Collaborative.

NIPSCO will file an annual Performance Metrics Collaborative Report for each year hereafter until otherwise indicated by the Presiding Officers.

Respectfully submitted:

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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 by email transmission upon the following:

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Robert Kelter
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Dated this 1st day of July, 2025.

Tiffany Murray

NIPSCO

July 1, 2025

Via Electronic Filing
Honorable James F. Huston
Chair
Indiana Utility Regulatory Commission
101 West Washington Street, Suite 1500 East
Indianapolis, Indiana 46204

RE: Cause No. 44688; Compliance Filing – Performance Metric Report

Dear Chair Huston:

Enclosed please find the Performance Metric Report prepared by Northern Indiana Public Service Company LLC ("NIPSCO") reporting 2024 results. As in previous years, NIPSCO provided the stakeholders involved in Cause No. 44688 with the opportunity to review and comment on the document, but the information was compiled by NIPSCO. Pages 3 through 5 of the report provide an overview of the 2024 results and the appendix includes the data utilized in developing the graphs.

NIPSCO appreciates the participation of the stakeholders, particularly during the June 10, 2025 meeting to review the 2024 results. Please contact me if you have any questions or concerns.

Sincerely,

Erin E. Whitehead
Vice President, Regulatory and Major Accounts

Encl.
cc: (w/ encl. – via email transmission) to Service List in Cause No. 44688

Northern Indiana Public Service Company LLC

2024 PERFORMANCE METRIC REPORT

Filed July 1, 2025

NIPSCO
A NiSource Company

TABLE OF CONTENTS

EXECUTIVE SUMMARY

Background

This document is the ninth performance metric report Northern Indiana Public Service Company LLC (“NIPSCO” or “Company”) has submitted to the Indiana Utility Regulatory Commission (“Commission” or “IURC”) in compliance with the Commission’s July 18, 2016, Order in Cause No. 44688 (the “44688 Order”). The purpose of this report is to communicate NIPSCO’s performance in areas such as safety, reliability, customer service, and operations in 2024. This report includes the same data sets used in prior reports and expounds on these metrics to enable interested stakeholders, the Commission, and NIPSCO, to understand and utilize key metrics. NIPSCO strives to deliver customer value in a balanced manner across four key dimensions – safety, customer experience, reliability, and affordability.

Safety

NIPSCO continues to promote a Stop Work Authority policy, which empowers employees to stop work whenever they see an employee, business partner, or member of the public who is at risk of harm. NIPSCO also continues its partnership with Vimocity, promoting NIPSCO Moves, which is a company led initiative aimed at preventing ergonomic strain and sprain injuries. In 2024, NIPSCO Moves was extended to all office employees and is now available to all NIPSCO employees and their families.

In terms of driving safety, NIPSCO successfully upgraded from the GreenRoads telematics program and partnered with Samsara. The new technology uses dual inward and outward facing cameras to detect unsafe driving behaviors and provides the driver with real time feedback for correction. Installs were completed for the entire NIPSCO fleet in 2024. Since installation, we have seen a significant reduction in driving events.

Reliability

Power Delivery: NIPSCO continues to work on its core reliability improvement programs, such as vegetation management and grid modernization, and is focused on improving its reliability metrics.

Power Generation: NIPSCO added a solar facility and a battery energy storage system (Cavalry Solar Field / Cavalry Battery Energy Storage System) in 2024, with both beginning operation in May 2024, expanding NIPSCO's renewable energy generation portfolio.

NIPSCO's coal EFOR has been significantly affected by changing power markets, which has impacted the economical dispatch for coal. NIPSCO's coal EFOR increased slightly in 2024 due to units not being dispatched as often and an increase in planned and maintenance outage hours in 2024. The EFOR at NIPSCO's Sugar Creek unit ticked up slightly from 2023 due to tube and steam leaks on the heat recovery steam generator.

Customer Service

In 2024, NIPSCO customer satisfaction increased over 2023 with the customer service representatives, the IVR (automated phone system), and the online self-service web experiences. First call resolution increased from 83% in 2023 to 89% in 2024 and average speed to answer continued to improve in 2024.

NIPSCO's 2024 J.D. Power Residential Customer satisfaction survey for the Midwest region of midsize utilities scores NIPSCO at 700, which is above the group average of 692 and the highest of the three Indiana electric investor-owned utilities in the segment. In J.D. Power's Business Customer satisfaction survey, NIPSCO received a score of 804, which is above the group average of 779, and the highest out of Indiana's three electric investor-owned utilities in the segment.

In 2024, 49 IURC complaints were filed by customers, and only two were substantiated. This reflects a slight uptick from the number of complaints filed in 2023 but is still significantly less than the number of complaints filed during the period of 2011 through 2019. The number of complaints trended downward during the pandemic years of 2020 and 2021.

Investment and Spending

NIPSCO continued to reduce operational O&M costs in many areas in 2024. Fuel and purchased power costs further decreased by $72 million, while total O&M costs decreased by $92 million, meaning that non-fuel O&M decreased by approximately $20 million in 2024 compared to 2023[1]. Total O&M costs, normalized on a per megawatt hour ("MWh") and per retail customer basis, also decreased for NIPSCO in 2024, driven by lower fuel and purchased power costs, non-fuel production expenses, and certain A&G expenses. NIPSCO's normalized non-fuel O&M costs slightly increased in 2023 compared to 2022 but reduced back to 2022 levels in 2024. Overall, non-fuel O&M has remained at a consistent level in the last 10 years, indicating that cost containment efforts at both NiSource and NIPSCO have continued to be effective.

Affordability

NIPSCO is committed to providing safe, reliable, resilient, stable, environmentally sustainable and affordable service to its customers.   In 2024, residential, commercial, and industrial customers all experienced an increase in their average monthly bill due to a base rate case implemented March 1, 2024. NIPSCO's investment in renewable generation resources, which is expected to yield long-term cost savings for customers, requires upfront capital that results in near-term rate increases.   NIPSCO residential customers also have the lowest average monthly usage of the Indiana investor-owned utilities, which can contribute to an overall lower average bill. NIPSCO continues to proactively communicate with customers via text, email, and phone calls, and work with customers to make payments manageable. NIPSCO has various payment plans that range from three months up to 12 months, and the Company encourages customers to sign up for budget billing to keep payments consistent throughout the year and promotes energy efficiency programs to help customers reduce usage. NIPSCO has also recently proposed a new bill assistance program for low income customers to assist with summer electric bills, deposits, and late payment fees, which is pending Commission approval.

Staffing

NIPSCO has realized a substantial decrease in employee turnover after seeing the metric peak in 2021. This decrease was mainly due to a significant decline in retirements. In 2024, there was a slight increase in turnover due to retirements and discharges. In 2024, NIPSCO also saw its percentage of both female and non-white employees increase, continuing a positive trend dating back to 2015.

[1] Fuel and purchased power costs had decreased by $138 million in 2023 (compared to 2022), while total O&M costs had decreased by $114 million. The non-fuel O&M had increased by approximately $24 million in 2023 compared to 2022.

SAFETY

Safety is a core value of the NIPSCO organization. The Company's safety policies reflect a "just culture" mindset, which is a model used by high consequence industries to improve the way they approach system safety and staff accountability.

Organizations foster a just culture by looking first at systematic issues rather than individual performance. This approach recognizes that all employees make errors, and therefore a company should design its systems and procedures so that when an error occurs, injuries are limited, due to multiple layers of protection. This is the "Fail Safely" approach incorporated by the Company.

NIPSCO employees have increasingly embraced safety initiatives over the past few years. Metrics used by the Company to measure its safety efforts are discussed below.

Vehicle Safety

As part of a continuous improvement initiative, NIPSCO installed Samsara telematics throughout our fleet in 2024. The new technology uses dual inward and outward facing cameras to detect unsafe driving behaviors and provides the driver with real time feedback for correction. The system can detect speeding, unsafe following distances, mobile device usage, rolling stops, inattentive driving, policy violations such as not using a seatbelt or mobile device usage, and harsh events, such as aggressive braking, turning, and acceleration. This system allows supervisors the opportunity to coach their employees' driving behaviors.

Installation of Samsara was completed in October 2024. In a comparison of the fourth quarter of 2024 to the first quarter of 2025, NIPSO has seen a 73% decrease in mobile usage and a 62% decrease in no seat belt usage.

Figure 1. Preventable Vehicle Crash Rate

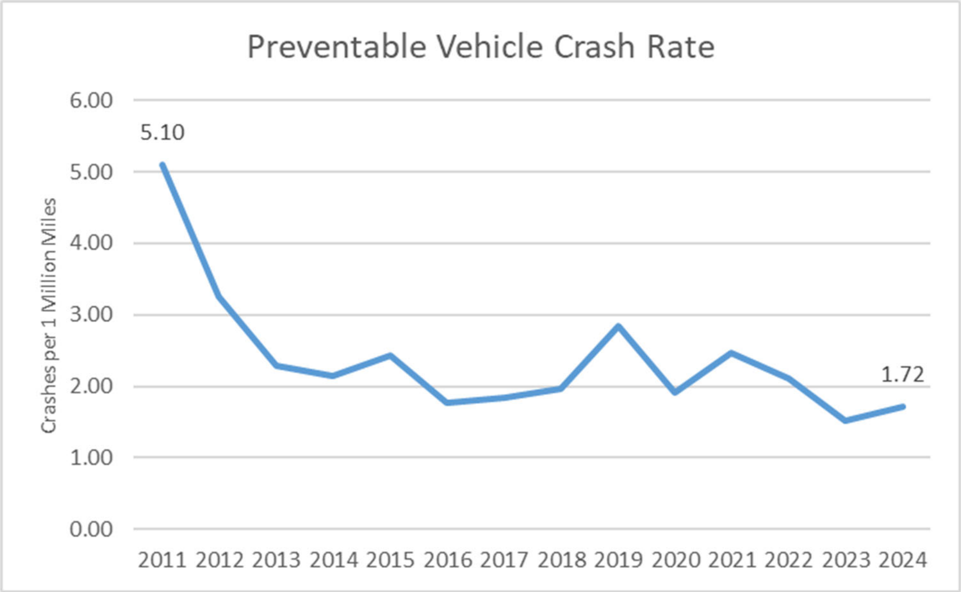


Figure 1 illustrates NIPSCO's preventable vehicle crash rate, which represents the number of crashes per one million miles driven, in which any employee, while driving on Company business, failed to do everything reasonably possible to avoid a collision. This metric is combined for gas and electric. The preventable vehicle crash rate remains relatively flat with only a slight uptick from 1.5 to 1.7 in 2024. Vehicle collisions with stationary objects continue to be a primary driver in our preventable vehicle crash rates. While previously minor contacts might have gone unreported, now the newly installed Samsara system will often register these events. This results in more events being documented and classified as preventable vehicle collisions, driving the overall vehicle incident rate up for the year. However, this improved reporting provides visibility into areas of focus for NIPSCO to continue efforts toward decreasing the vehicle crash rate going forward.

Field Safety

NIPSCO strives to make safety a foremost priority for its employees every day. Supervisors are encouraged to begin each meeting with a safety moment in an effort to ensure safe working practices become ingrained in the Company's culture. Field employees receive Human and Organizational Performance ("HOP") training, which includes emphasis on human error reduction tools, such as pre-job briefing and Stop Work Authority. The Company is committed to ensuring its employees have a deeper understanding of human error and how to prevent it. HOP places an emphasis on organizational weaknesses as well as understanding personal capabilities, assessing levels of risk, and controlling that risk through use of layers of protection and error prevention techniques. Employees conduct a pre-job briefing before each work task, which includes the identification of unique site hazards, special precautions, required personal protective equipment, energy control, and critical work procedures. Local management then reviews these briefings to follow up on any potential operating issues. NIPSCO continues to promote a Stop Work Authority policy, which empowers employees to stop work whenever they see an employee, business partner, or member of the public who is at risk of harm.

The OSHA recordable incident rate, in Figure 2, represents the number of recordable injury or illness cases for every 100 full-time generation and power delivery employees. Most injuries or illnesses that require more than first aid treatment are recordable.

The days away, restricted, or transferred (DART) metric, in Figure 2, represents the number of injury or illness cases requiring days away, restricted duty, or job transfer for every 100 generation and power delivery full-time employees. This number indicates the rate of injuries that result in an employee being unable to perform their typical job requirements.

Figure 2. Employee Injuries – Generation and Power Delivery Divisions

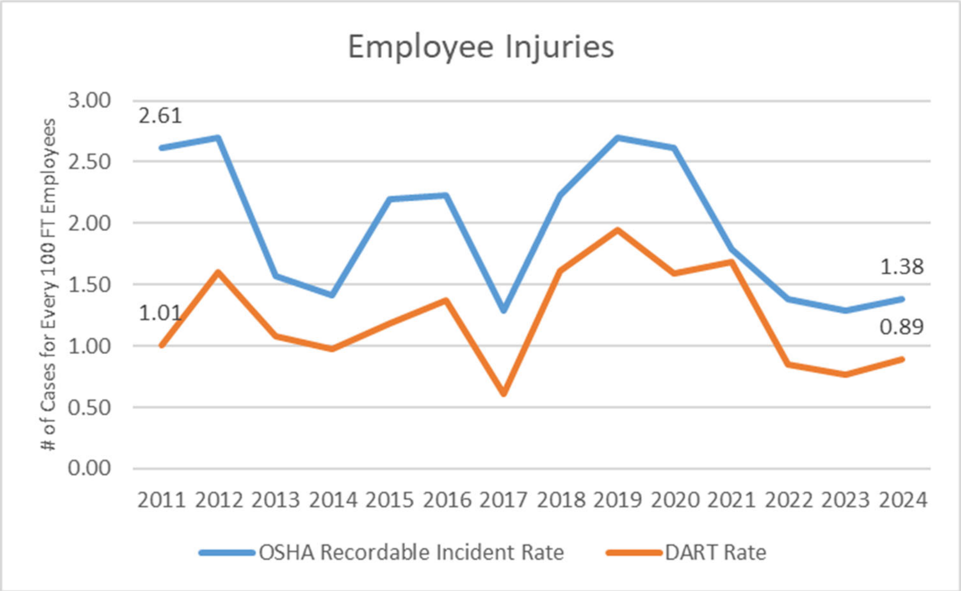


Figure 2 illustrates the two metrics NIPSCO uses to measure employee safety in the field for electric employees in the generation and power delivery divisions. NIPSCO continues to focus on improving these metrics.

Figure 3. Employee Injuries – NIPSCO with Business Service Allocation ("BSA")

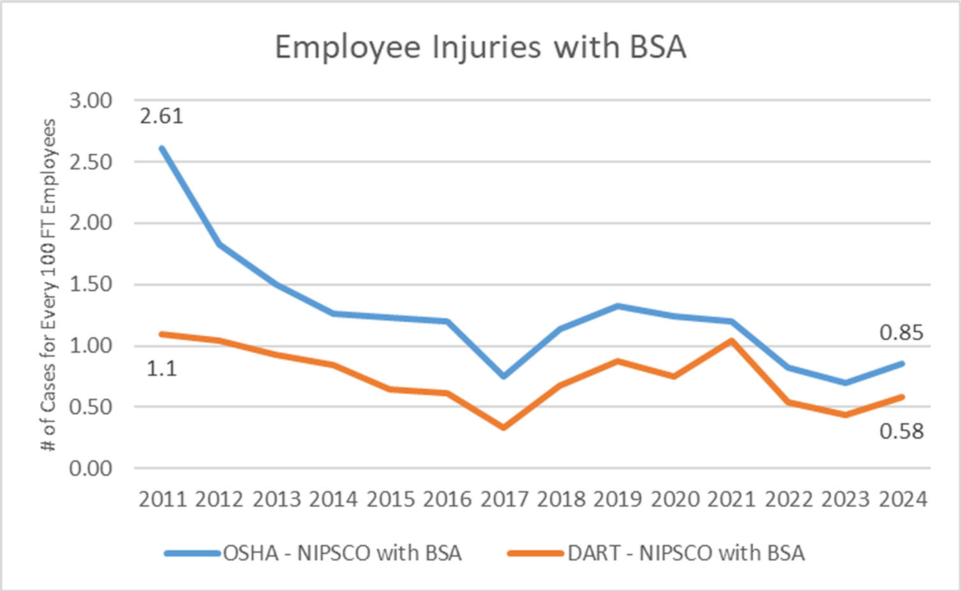


Figure 3 illustrates the two metrics NIPSCO uses to measure employee safety in the field for all NIPSCO employees. In comparison to 2023, NIPSCO's OSHA recordable rate and DART rate for 2024 slightly increased, but NIPSCO remains focused on continued safety improvements.

During 2024 NIPSCO rolled out an injury prevention program through a partnership with a third-party telemedicine provider that emphasizes proactive care for more minor injuries as a response to our ongoing challenges with strain and sprain style events. This has resulted in increased treatment of minor events that might previously have gone unreported, leading to a slight increase in injuries in 2024.

NIPSCO benchmarks this metric against AGA data for combination gas and electric utilities. In 2024, NIPSCO was in the second quartile in this category.

NIPSCO's safety culture has made progress over the years. NIPSCO continues work on its SMS, with integration and expansion of the program into its electric operations. The SMS program is based on American Petroleum Institute Recommended Practice 1173. SMS is anchored by NIPSCO's Core Four Responsibilities, which include: (1) Following Our Processes and Procedures; (2) Identifying and Reporting Risks; (3) Continually Improving Processes and Procedures; and (4) Identifying and Proactively Taking Action.

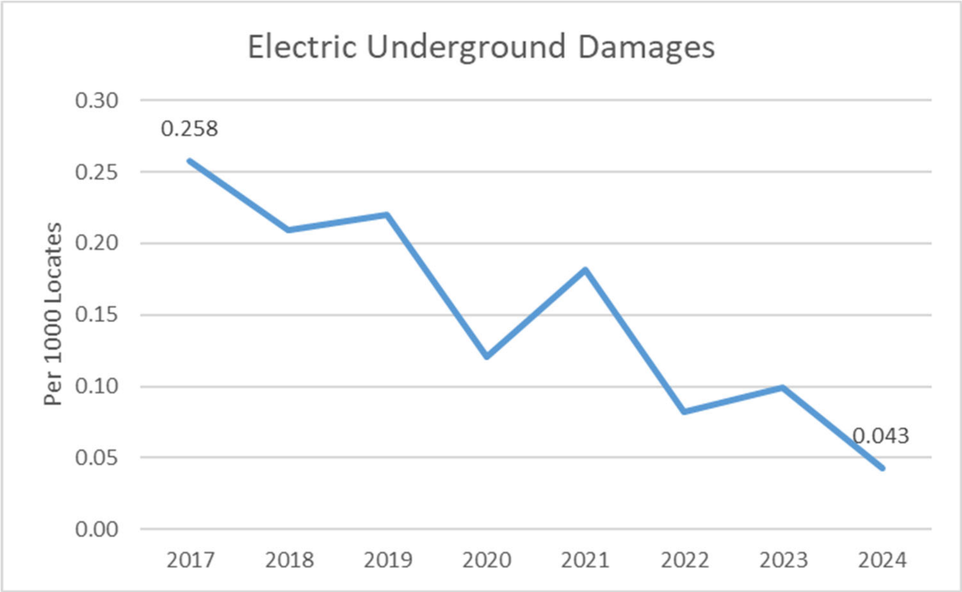
NIPSCO's SMS journey is taking safety to a new level of continuous improvement. It brings together people, processes, and culture to proactively find and act on risks to employees, contractors, customers, and communities. The Corrective Action Program ("CAP") is a foundational part of that effort. The CAP offers a simple way to document identified risks and a systematic process to review, prioritize, address, and track progress to reduce risks. Submitting an issue, concern, or risk in the CAP starts a rigorous process that can lead to resolving a prioritized risk through corrective action.

Maintaining our focus on combatting ergonomic hazards, NIPSCO has continued our partnership with Vimocity through the NIPSCO Moves program. This includes development of targeted resources, such as video material demonstrating improved body positioning during high-risk tasks, and lessons learned documents to identify opportunities for improvement when ergonomic injuries occur.

Electric Underground Damages

Figure 4 illustrates the *electric underground damages* metric. This metric represents the number of reported electric damages, divided by the number of electric locate tickets received through the 811 process, multiplied by 1,000. This metric has been steadily improving dating back to 2017 due to increased communication and awareness to call 811 before you dig. In 2024, there were 12 reported electric damages out of 279,070 locate tickets received by NIPSCO through the 811 process.

Figure 4. Electric Underground Damages per 1000 Locates



RELIABILITY

Power Delivery

Utilities use three principal indices to measure service reliability.

1. System Average Interruption Duration Index ("SAIDI"): represents the average outage duration of each electric customer served. A customer must lose service for five minutes or more for the incident to be defined as an interruption.

$$SAIDI = \frac{\sum electric\ customer\ outage\ minutes}{electric\ customers}$$

2. System Average Interruption Frequency Index ("SAIFI"): represents how many times per year the average customer experiences an interruption in electric supply. A customer must lose service for five minutes or more for the incident to be defined as an interruption.

$$SAIFI = \frac{\sum electric\ customer\ interruptions}{electric\ customers}$$

3. Customer Average Interruption Duration Index ("CAIDI"): represents the average length of outage for customers who experience an outage. CAIDI is therefore equal to SAIDI divided by SAIFI. A customer must lose service for five minutes or more for the incident to be defined as an interruption.

$$CAIDI = \frac{\sum electric\ customer\ outage\ minutes}{electric\ customer\ interruptions}$$

A major event day ("MED") is a day on which a weather or operational event causes a utility's daily SAIDI to exceed a calculated threshold ("TMED").[2] A single event may cause multiple MEDs and power outages may continue for days after the event is over.

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[2] The TMED calculation is based on IEEE Standard 1366-2012 and uses a utility's daily SAIDI values for the past five reporting years.

Figure 5A. Major Event Day Metrics

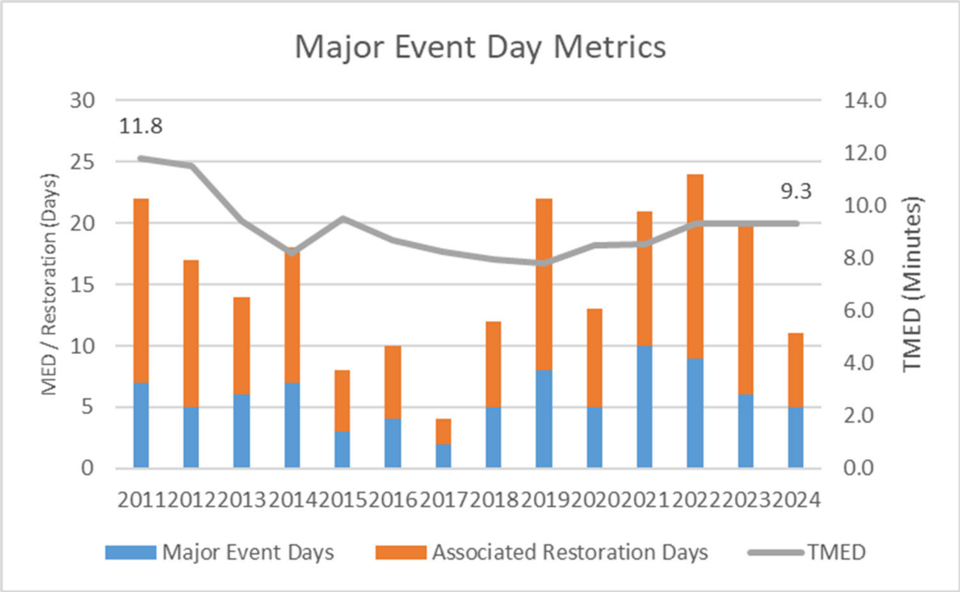


Figure 5A illustrates the number of MEDs in NIPSCO's service territory, the number of restoration days associated with those MEDs, and the TMED used to identify major event days each year. The five MEDs and six associated restoration days in 2024 represent a decrease from 2023 figures.

In an effort to improve reliability for power delivery, NIPSCO has steadily increased funding for its vegetation management program, specifically focusing on trimming more circuit miles on distribution and sub-transmission circuits. Much of the increase in funding is directed toward circuits with the highest tree-related outages and/or highest customer impacts. This plan has resulted in a decreasing trend in tree-related outages over the years, but with a slight increase in 2024, as shown in Figure 5B.

The future of NIPSCO's vegetation management program also recognizes the changing climate conditions and the challenges that come with maintaining vegetation sustainably, while continuing to drive down tree-related outages. During 2024, NIPSCO's vegetation management team began to use advanced data analytics to assist in the development of future year work plans. This data was used in 2024 to ensure the focus of the program combines tree related outages, vegetation imagery, and efficient cost control. NIPSCO trimmed 954 miles in 2023 and 1,157 miles in 2024.

Figure 5B. Number of Tree-Related Outages

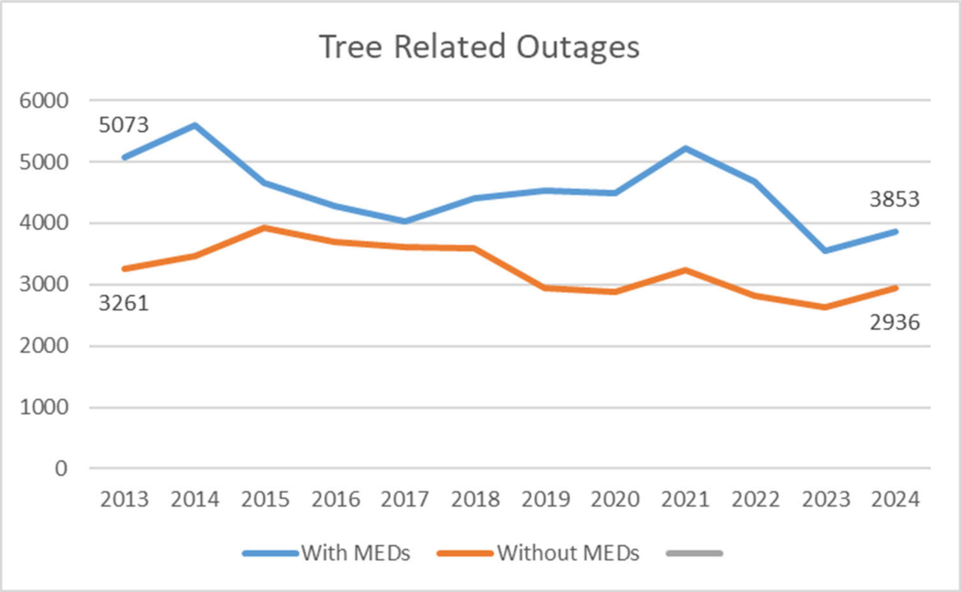


Figure 6. Reliability Indices (including MED)

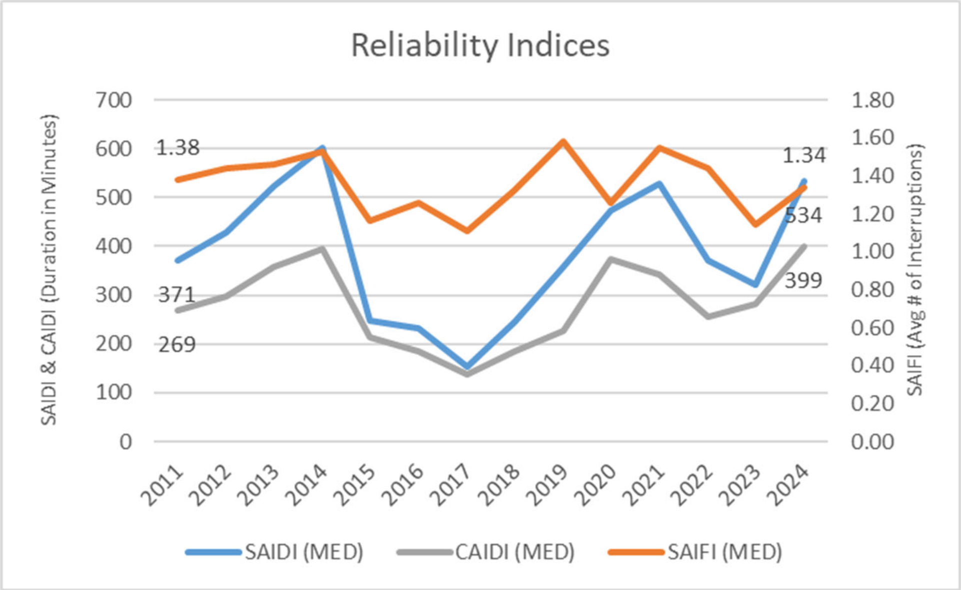


Figure 6 illustrates NIPSCO's three reliability indices, using MED data. MEDs are primarily storms or severe weather events that are more destructive than typical storm events.

For the 12-month period ending December 31, 2024, there were five storm events in NIPSCO's electric service territory that met the minimum criteria for a "major event trigger" and encompassed six days. In addition, there were nineteen weather events that NIPSCO would consider as severe (> 20% of TMED in a 24-hour period).

Figure 7. Reliability Indices (excluding MED data)

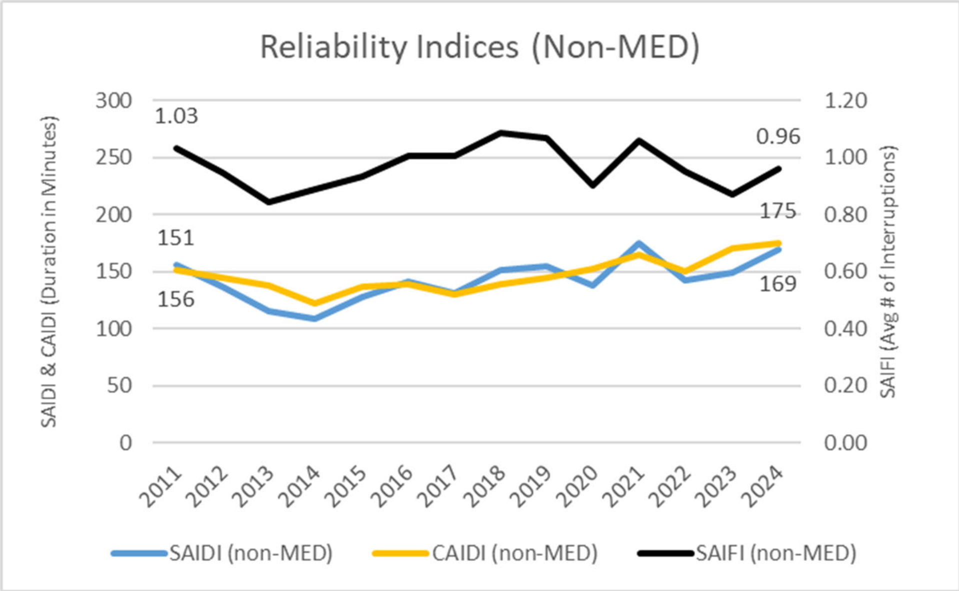


Figure 7 illustrates NIPSCO's three reliability indices, excluding MED data, which is identified using TMED. If a utility's daily SAIDI exceeds the TMED, the outage data on that date is excluded from the utility's non-MED reliability indices.

For SAIDI, in 2024, NIPSCO saw a slight increase of twenty minutes compared to 2023. NIPSCO's SAIDI has generally been slightly above the IEEE industry median for medium-sized utilities since 2015. IEE industry data for 2024 will not be available until after this report is submitted.

For SAIFI, in 2024, the average NIPSCO electric customer experienced a power interruption 0.96 times. This represents an increase from the 2023 figure of 0.87. NIPSCO's SAIFI has generally been below (better than) or just slightly above the IEEE industry median for medium-sized utilities.

For CAIDI, in 2024, NIPSCO saw an increase of four minutes compared to 2023. NIPSCO's CAIDI has been above the IEE industry median for medium-sized utilities since 2011.

NIPSCO continues to invest in its electric system to improve reliability, through its grid modernization program under its transmission, distribution, storage system improvement charge (TDSIC) plan, approved by the Commission in Cause No. 45557. TDSIC and other capital investments have had a positive impact on NIPSCO reliability and resiliency. NIPSCO's grid modernization program focused on increasing visibility and control for

NIPSCO T&D system for better planning, decreased outage frequency, and decreased response times for outages. Through communication expansion, substation and distribution automation, over 39,000 customer interruptions were avoided in 2024, We estimate a savings of approximately 30% of customer interruptions by 2034, which will positively impact our SAIFI metric.

NIPSCO is also focused on aging infrastructure to address assets in poor condition and/or at end of life. This includes planned replacements, removing unplanned, long duration outages, such as substation transformer failures or underground cable failures. Over 90% of NIPSCO's underground faults are associated with its unjacketed cable population; hundreds of miles have been replaced, removing potential future outages. 85% less customer interruptions on circuits were addressed through this program. Wood and steel life extension programs have strengthened the existing support structures fleet while removing those at their end of life under planned conditions.

NIPSCO's TDSIC efforts also address deliverability and capacity by focusing on upgrading the system to accommodate load growth, while providing capacity to back up other loads during an outage event. Substation equipment and circuit conductors have been upgraded to meet load demand before asset fail due to overloads. New circuit tie points to provide alternative sources in the event of an outage have been created, allowing customers to be restored faster.

NIPSCO is also upgrading its distribution automation system to isolate and restore customers, which is intended to reduce outage severity and duration, improving the customer experience. In addition, NIPSCO investigates all outages affecting more than 1,000 customers and utilizes lessons learned to improve construction standards, material selection, system configuration, and operating procedures.

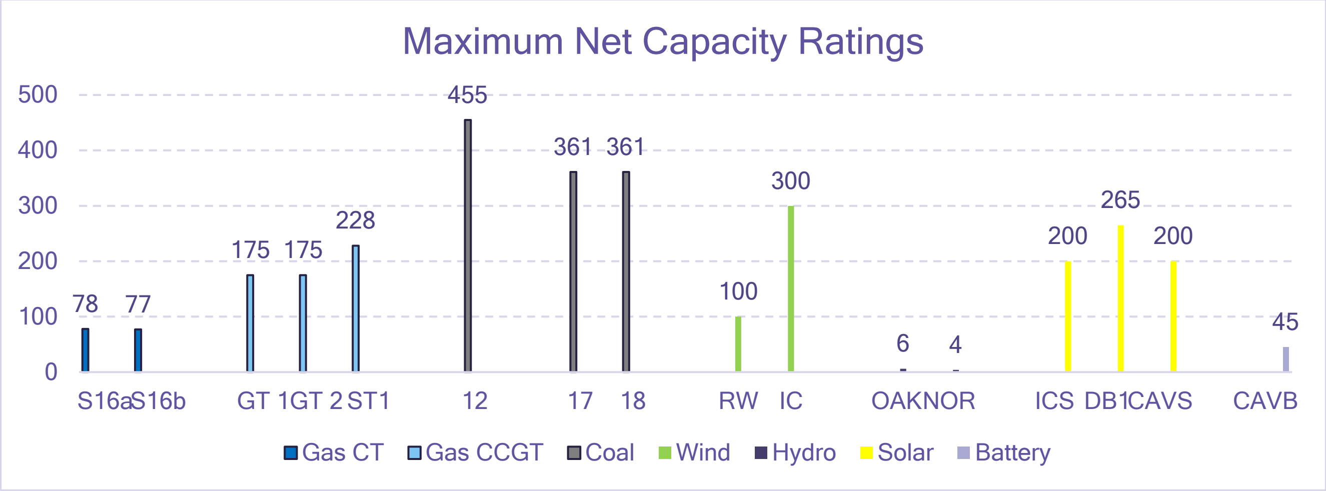
NIPSCO has a large amount of rural service territory, which affects deployment of service teams, and is located near Lake Michigan, which has effects on weather patterns, and such weather compounds the effects of the rural service territory. Also, NIPSCO is still in the process of fully deploying advanced metering infrastructure ("AMI"), whereas other utilities in Indiana have completed or are near completion.

Reliability indices are impacted due in part to the need in many cases for NIPSCO to tie circuits to adjacent substations or circuits during construction activities, which when an outage occurs on circuits that are tied, it results in an increased number of impacted customers. NIPSCO anticipates that improvements in its current TDSIC plan, which includes grid modernization investments and the full deployment of technologies like AMI, will improve NIPSCO's response and outage restoration times through faster outage reporting, allowing crews to be dispatched quicker. These technologies will also help NIPSCO locate damaged assets by reducing the patrol time that is currently required. This aligns with NIPSCO's focus to improve these metrics for the benefit of customers and to positively impact reliability.

Power Generation

NIPSCO's generating facilities have a total installed capacity of 3,030 net megawatts ("MW") and consist of ten separate generation sites, including Schahfer Generating Station (Units 16A, 16B, 17 and 18), Michigan City Generating Station (Unit 12), Sugar Creek Generating Station (SC1, SC2, and SS1), Rosewater Wind Farm , Indiana Crossroads I Wind Farm , Dunns Bridge Solar Farm, Indiana Crossroads Solar Farm, Cavalry Solar Field / Cavalry Battery Energy Storage System[3], and two (2) hydroelectric generating sites (Oakdale and Norway). The power generation metrics present NIPSCO's generation productivity by large generator type: coal, gas combustion turbine, combined cycle natural gas, hydroelectric, solar, wind, and battery storage.

Figure 8A. Installed Net Capacity of Generating Units (MW)



[3] Cavalry Solar (CAVS) and Cavalry Battery Energy Storage System (CAVB) interconnection output limited to 200 MW.

Figure 8A illustrates NIPSCO's current generation portfolio, in MW.

Effective with Planning Year 2023-2024, MISO began awarding thermal resource accreditation seasonally, based on each resource's availability during all hours, and hours with the tightest operating conditions, to reflect the actual availability of resources when they are most needed.

Figure 8B.[4]

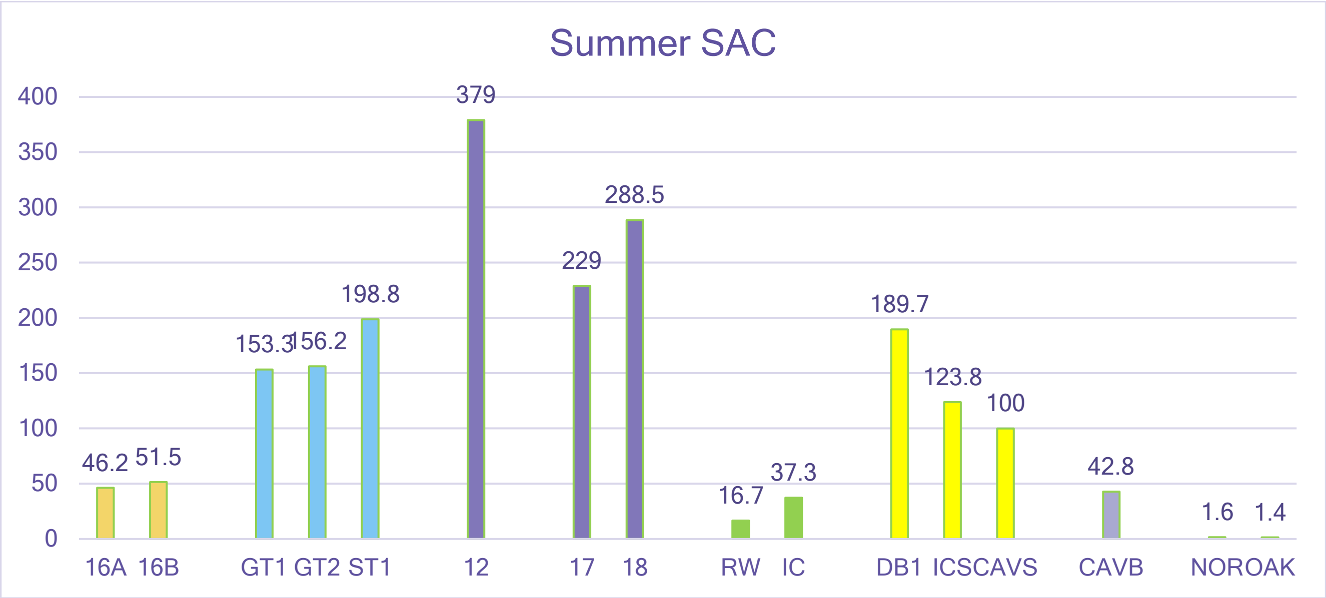


Figure 8B shows the summer Seasonal Accredited Capacity (SAC) for NIPSCO generating units.

Figure 8C illustrates the SAC for NIPSCO's generating units for the fall season.

[4] Dunns Bridge 1 Commercial Operation Date was later than the start of the summer season.

Figure 8C.

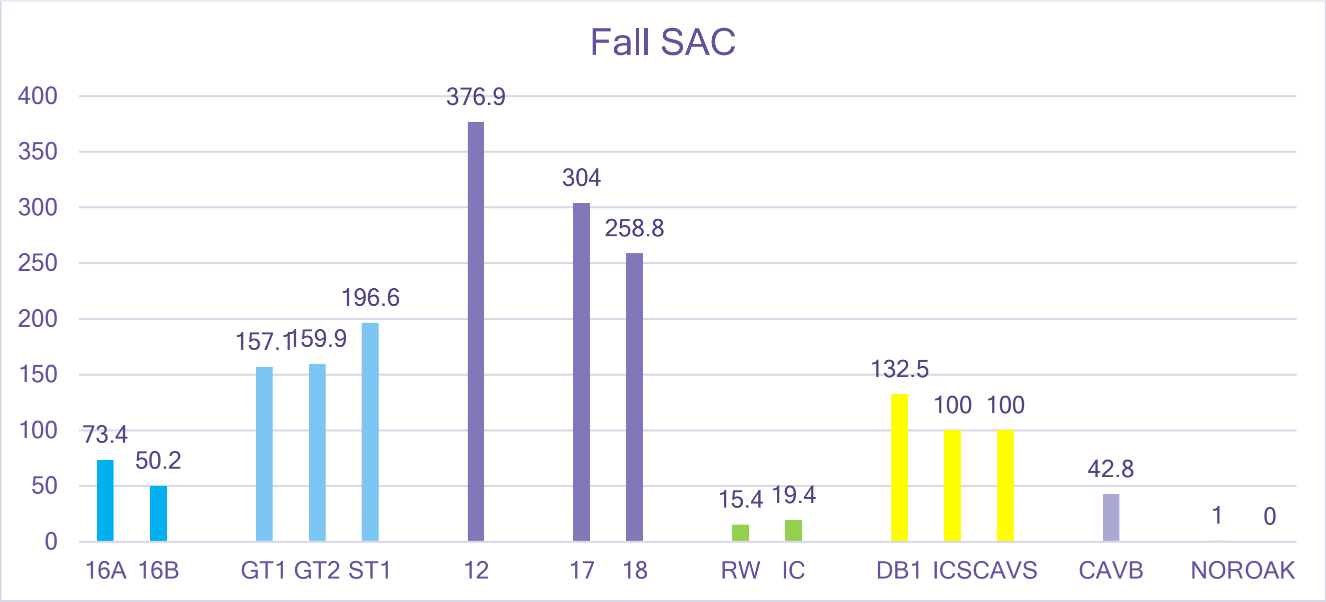


Figure 8D illustrates the SAC for NIPSCO's generating units for the winter season.

Figure 8D.

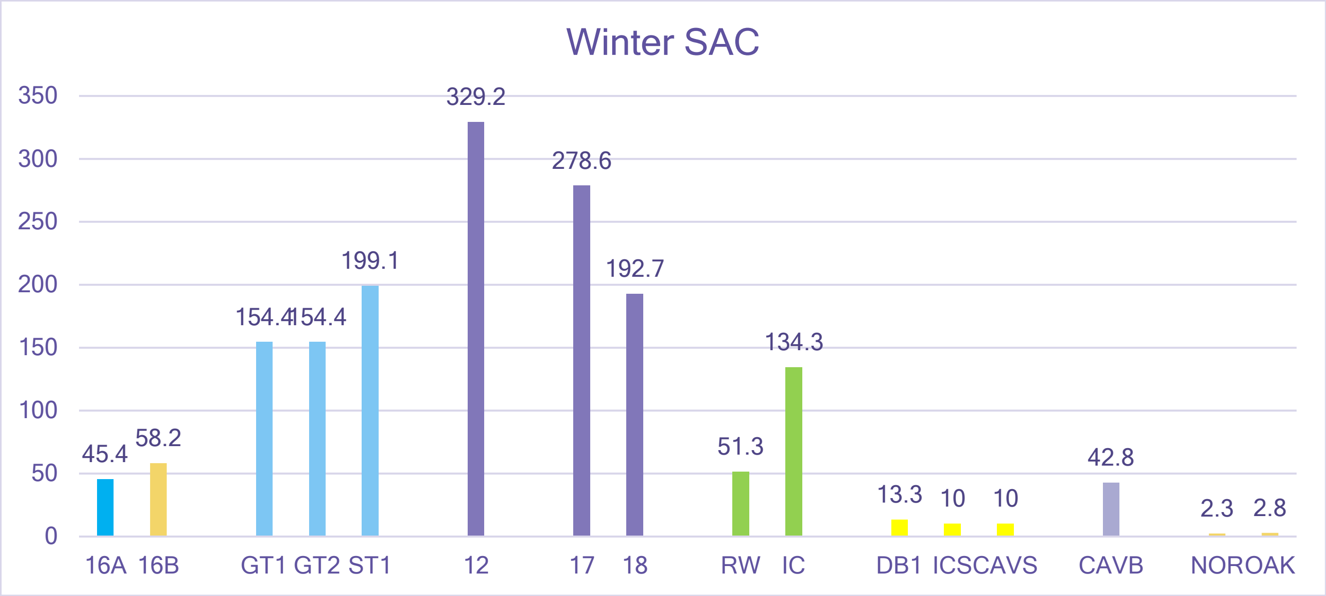


Figure 8E illustrates the SAC for NIPSCO's generating units for the spring season.

Figure 8E.

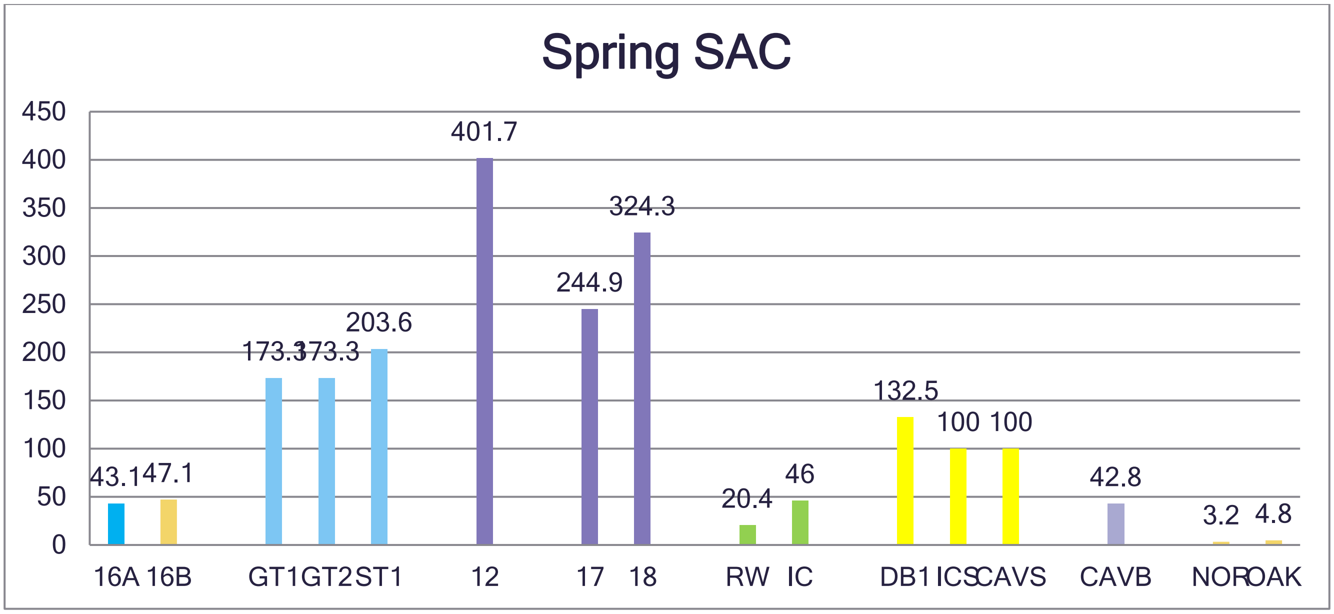
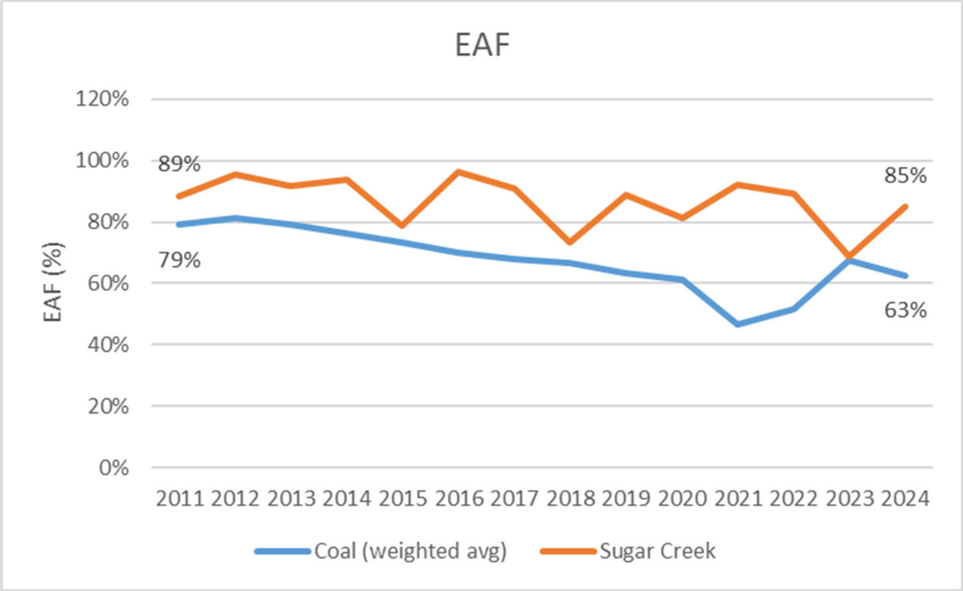


Figure 9 illustrates the equivalent availability factors ("EAF") of NIPSCO's coal and combined cycle units.[5] This metric represents the percentage of time a unit was available to generate power. The "equivalent" part of the definition accounts for times in which the unit was derated, meaning it could generate power but not up to 100% of its potential.

Figure 9. Equivalent Availability Factor



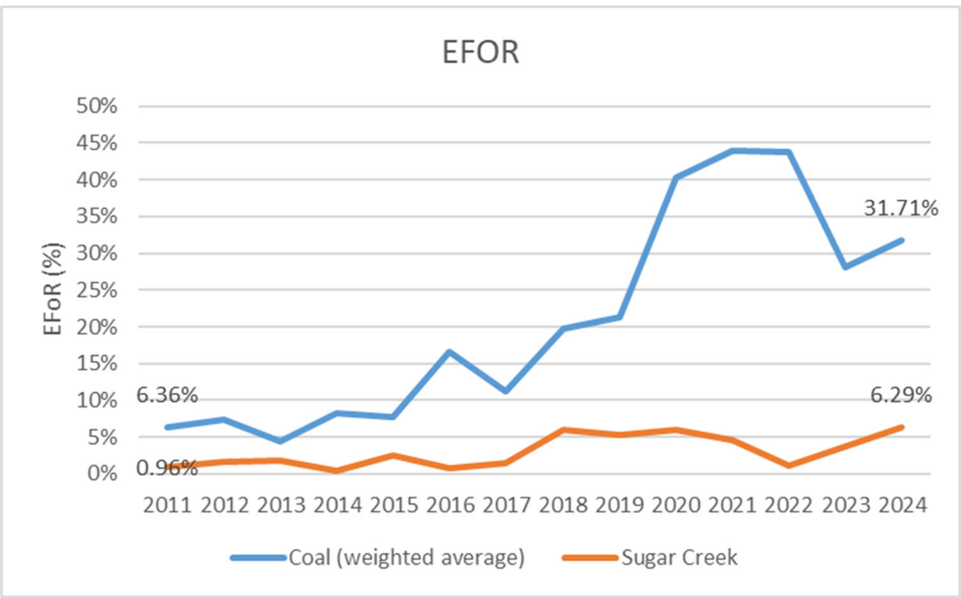
5 EAF = [(Available Hours - Equiv. Planned Derate Hours - Equiv. Unplanned Derate Hours) / Period Hours] × 100%.

There has been an increase in forced and maintenance outages over the past 12 years, due to aging equipment and systems, which has reduced the EAF over this period. Maintenance outages are performed when energy demand is low and units may be removed from service without significantly impacting electric system capacity. Coal unit availability decreased slightly in 2024 due to more planned and maintenance outage hours spent preparing Schahfer units for their last year of operation. All other outage factors impacting availability were similar to those in 2023. Sugar Creek's availability increased in 2024, primarily due to a shorter planned outage period than the previous year. This allowed the units to be dispatched more in 2024.

Figure 10 illustrates 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.

$$EFOR = \frac{FO + EFD}{FO + S + EFDRS} \times 100\%$$

Figure 10. EFOR[6]



A unit may be unable to generate power for reasons other than planned maintenance, when a forced outage (FO) occurs, or when a unit experiences an equivalent forced derate (EFD), in which a unit is unable to produce 100% of its typical capacity. The denominator in the

[6] Coal includes Michigan City Unit 12, and Schahfer Units 17 and 18.

equation is the sum of FO hours, service hours, and EFD hours, when the unit is in reserve shutdown.

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. The coal EFOR increased slightly in 2024. Although the forced outage hours decreased from 2023, fewer service hours caused the EFOR uptick, due to units not being dispatched as often and an increase in planned and maintenance outage hours in 2024.

Sugar Creek's EFOR increased from 3.72% in 2023 to 6.29% in 2024. The primary reason for the slight uptick in EFOR from 2023 was tube and steam leaks on the heat recovery steam generator. Sugar Creek had three such events in 2024. Additionally, CT 1A was out of service for the first 24 days in January due to rotor damage caused by a contractor that carried over from the Winter planned outage in 2023.

Figure 11. Coal Generation[7]

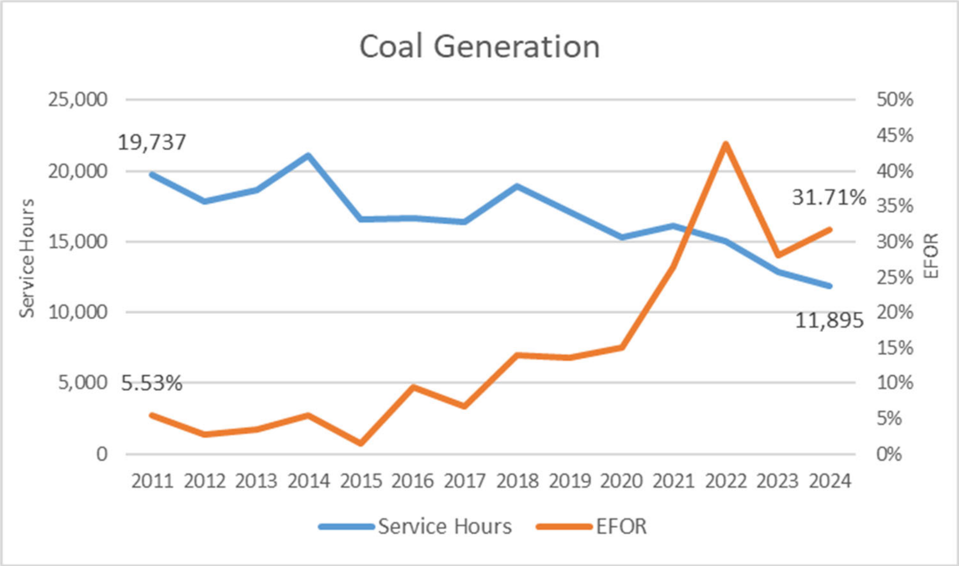


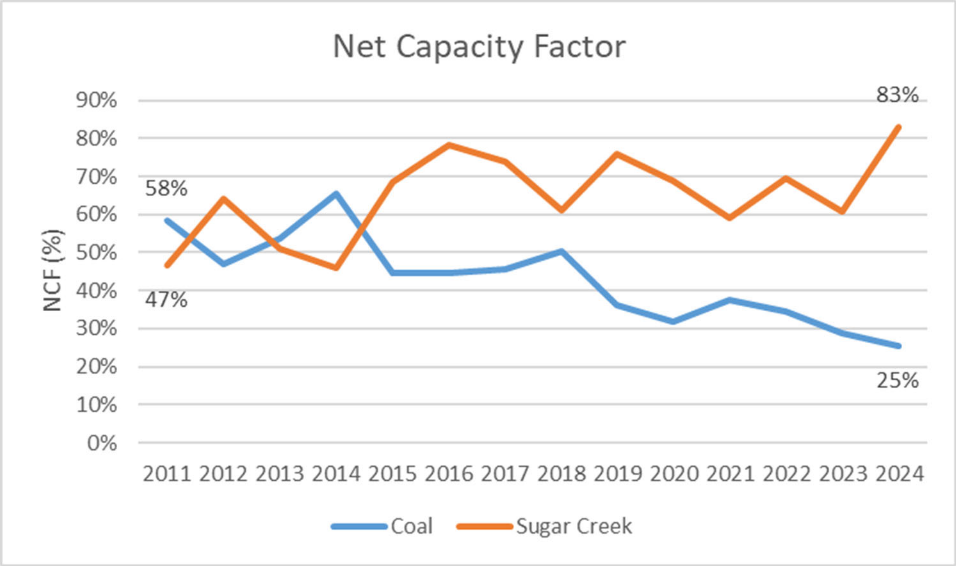
Figure 11 illustrates the relationship between the total service hours of NIPSCO's coal generation and the EFOR of those units. All things being equal, as service hours decrease over time, the EFOR increases. If a unit is available but not dispatched, the EFOR remains

[7] Service hours include only Michigan Unit 12 and Schahfer Units 17 and 18.

static. In 2024, the service hours remained low, primarily due to being dispatched less and more planned and maintenance outage hours in 2024.

Figure 12 illustrates the net capacity factor ("NCF") of NIPSCO's fossil fuel units. This metric represents the percentage of a unit's full capacity that it is allowed to produce, on average, during the period.

Figure 12. Net Capacity Factor[8]



NCF is a function of a unit's availability and its variable operating costs. A unit that has frequent forced or planned outages, or high operating costs compared to other generating units, will have a lower capacity factor. A unit's NCF is affected by the amount of time it is available to run, but has not been selected, due to economics. A unit that is always available to generate and has competitive operating costs will have a higher capacity factor. This largely explains why NIPSCO's gas-fired units at Sugar Creek have a much higher NCF than its coal-fired units. The coal capacity factor continues to decrease year-over-year, due to being dispatched less, as more renewable assets are commissioned.

[8] Generating units continue to consume a small amount of power even when they are not generating energy. This auxiliary power is subtracted from a unit's generation total and decreases the unit's NCF. Coal includes only Michigan City Unit 12 and Schahfer Units 17 and 18.

Renewable Generation

Figure 13 illustrates the NCF of NIPSCO's wind assets. Rosewater had a lower than forecasted NCF for 2024 due to lower than forecasted wind resources and turbine main bearing repairs. Indiana Crossroads Wind I had a lower than forecasted NCF as well due to lower than forecasted wind resources because of variability in the forecasted weather which resulted in lower wind than forecasted.

Figure 13. Wind Net Capacity Factor (NCF)

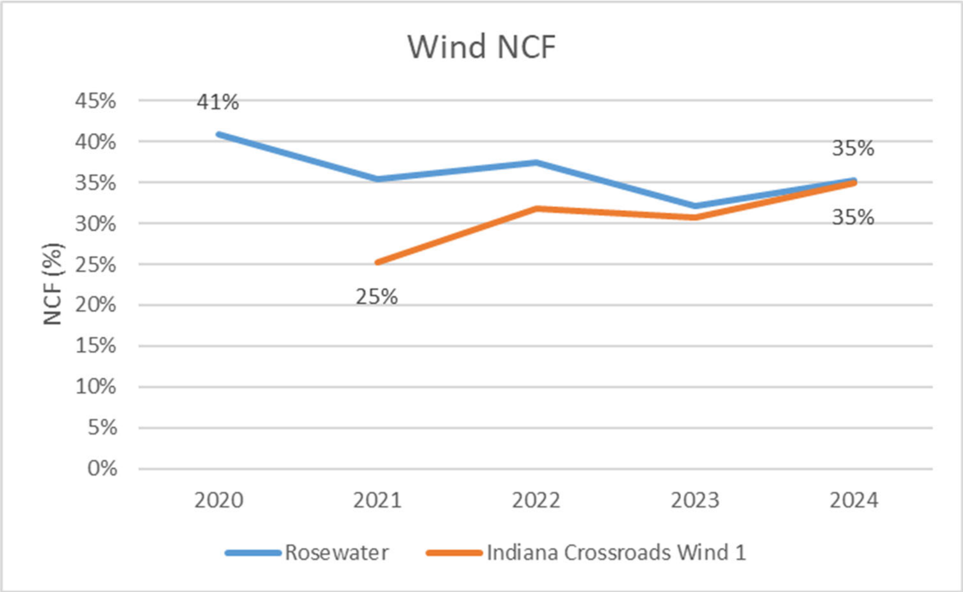


Figure 14 illustrates the NCF of NIPSCO's solar assets. Indiana Crossroads Solar and Dunns Bridge I had lower than forecasted NCF for 2024 due to inverter reliability issues. Cavalry Solar, which became operational in May 2024, had a lower than forecasted NCF due to PV panel replacements and post construction activities.

Figure 14. Solar Net Capacity Factor (NCF)

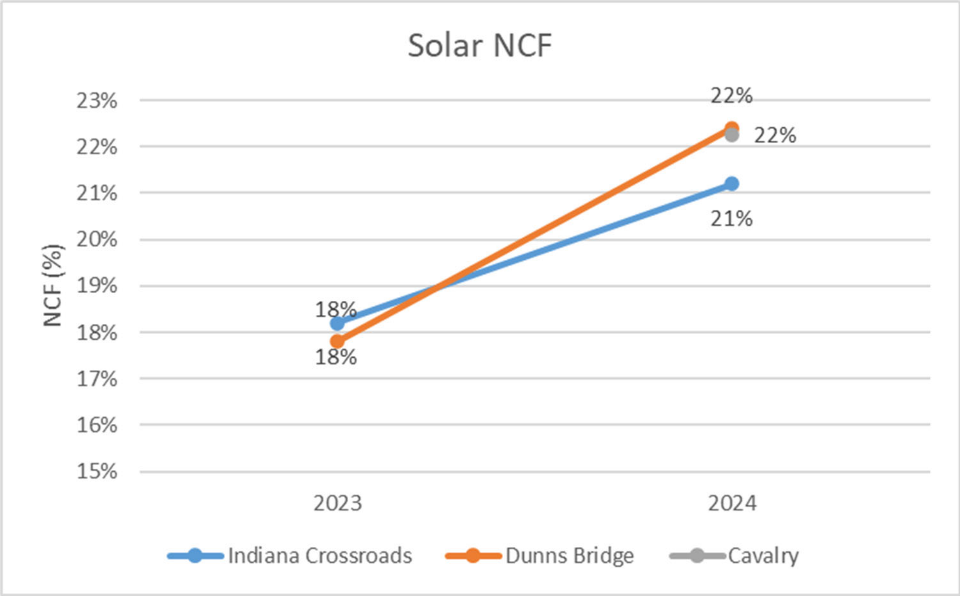


Figure 15 illustrates the Gross Energy Availability ("GEA") of NIPSCO's wind assets. This metric represents the facilities' potential to produce energy considering all downtime events. This metric is calculated as actual production divided by the sum of actual production and lost production due to downtime or curtailment restrictions. Both wind farms had a higher than forecasted GEA due to minimal gross losses with respect to forecast.

Figure 15. Wind Gross Energy Availability

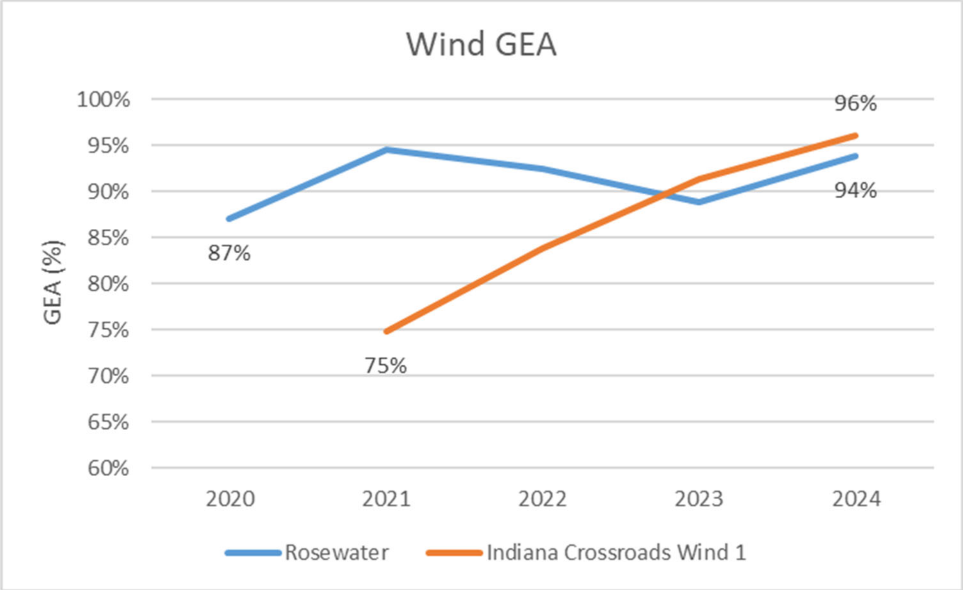


Figure 16 illustrates the Net Performance Ratio ("NPR") of NIPSCO's solar assets. This metric is the ratio of the actual generation compared to the theoretical maximum generation based on the DC nameplate capacity. This metric is calculated as the actual production divided by the theoretical maximum generation due to irradiance and PV panel temperatures. Indiana Crossroads Solar and Dunns Bridge I had a lower than forecasted NPR in 2024 due to inverter reliability issues. Inverter retrofits have taken place at the majority of our facilities and will be fully complete by Q3 2025. These retrofits will increase the equipment-related reliability of our fleet and increase our NPR. These retrofits are covered under warranty by the Original Equipment Manufacturer. Cavalry had a lower than forecasted NPR in 2024 due to PV panel replacements and post construction activities.

Figure 16. Solar Net Performance Ratio

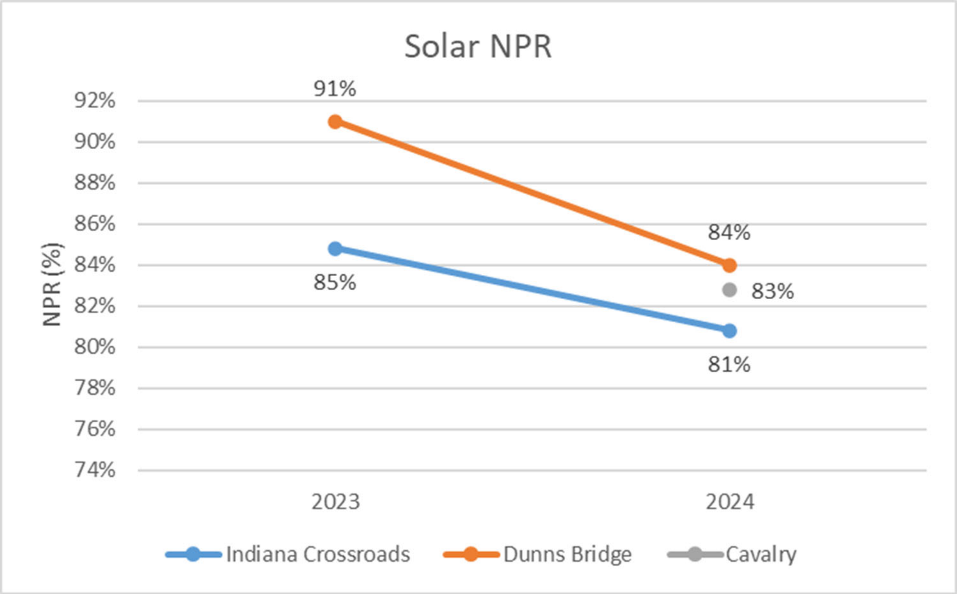


Figure 17 illustrates the Technical Energy Availability ("TEA") of NIPSCO's wind assets. This metric represents the facilities' potential to produce energy, considering downtime caused by turbine and balance of plant events, and excludes environmental, grid, and curtailment events. It is calculated as actual production divided by the sum of actual production and lost production due to technical downtime. Rosewater had a lower than forecasted TEA for 2024 due to main bearing repairs. Indiana Crossroads Wind I had a higher than forecasted TEA due to minimal technical losses.

Figure 17. Wind Technical Energy Availability

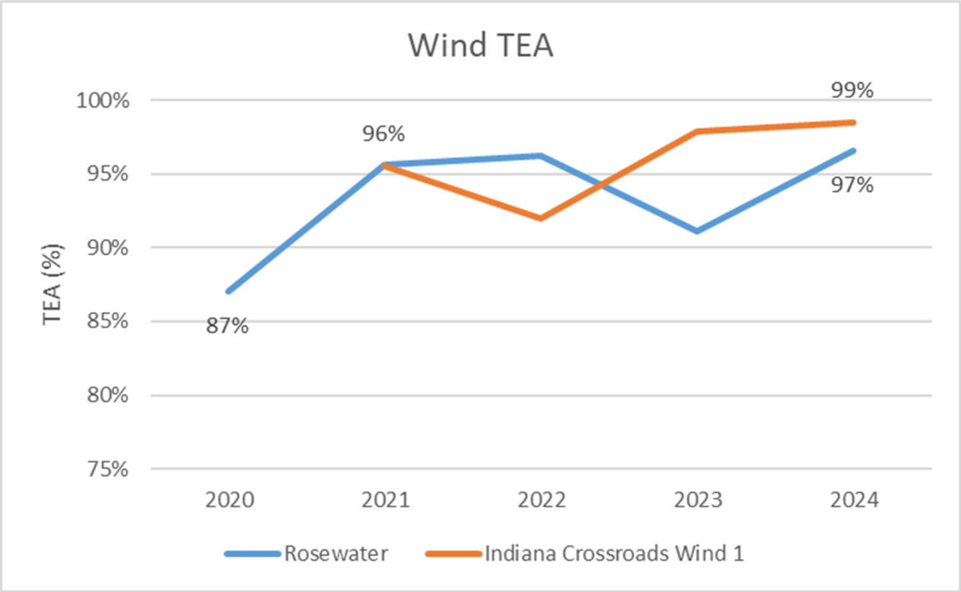
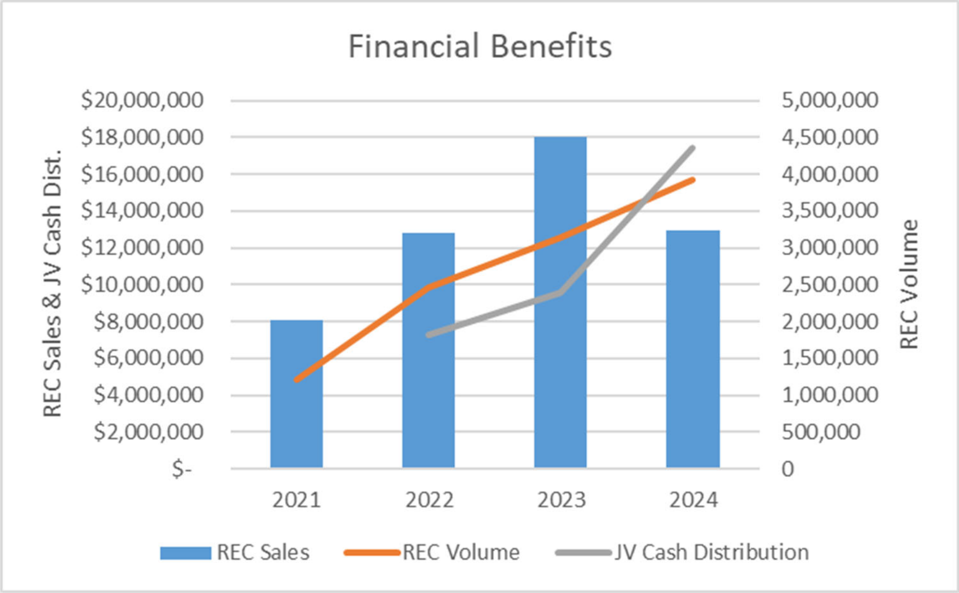


Figure 18 shows the financial benefits flowing back to customers associated with renewable projects that NIPSCO has brought online since 2020.

Figure 18. Financial Benefits Flowing Back to Customers



Renewable Energy Credit (REC) Sales - Each megawatt hour of power generated from a qualified resource can be awarded a REC. Many state jurisdictions require sellers of renewable power to have such RECs to certify that the source is in fact a qualified renewable resource. The amount of sales listed in Figure 18 includes all RECs sold by NIPSCO, including those coming from wholesale purchase power agreements, joint ventures with a tax equity partner, and wholly owned solar facilities. The 2024 volume is higher than 2023, however, 2024 experienced a significant dip in pricing, lowering the overall amount for REC sales. Note: Rosewater Wind and Jordan Creek Wind were NIPSCO's first renewable energy projects, starting near the end of 2020. While these projects generated REC sales in 2020, they were not significant enough to include on this graph.

Joint Venture (JV) Cash Distribution – When the proceeds from a power purchase agreement between NIPSCO and the applicable JV exceed the JV's operating costs (and after a certain amount of contingency has accumulated), NIPSCO passes back the excess funds to its customers, serving as a direct reduction to FAC costs on a dollar-for-dollar basis.

DISTRIBUTED GENERATION

As part of NIPSCO's Cause No. 45772 settlement agreement, NIPSCO agreed to provide data related to distributed generation in its PMC Report. Specifically, NIPSCO agreed to provide monthly customer participation data for NIPSCO's Excess Distributed Generation (EDG) tariff and Small Power Production tariff, broken down by residential and non-residential customers, including data on both new and total (a) capacity (kW-ac) installed, (b) number of customers, and (c) size of battery storage system (both kW and kWh), if one is part of the customer's system.

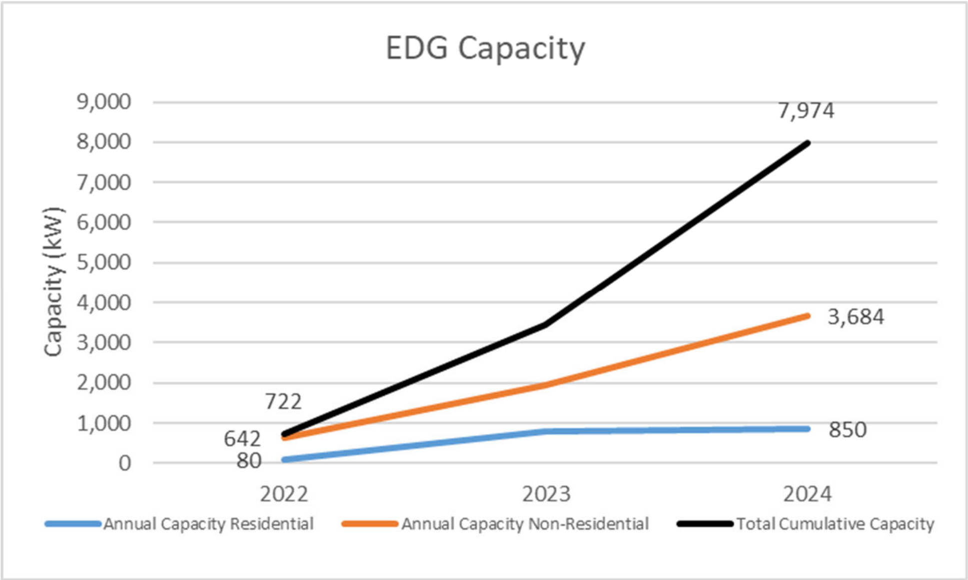
2024 monthly metrics are shown in Figure 19. NIPSCO showed increases in capacity installed, number of customers, and amount of battery storage in 2024, compared to 2023. NIPSCO has also included a cumulative row at the bottom of Figure 19, to show total EDG metrics as of 2024.

Figure 19. Excess Distributed Generation - 2024 - Monthly Data

2024 EDG								
	Non-Residential				Residential			
	Number of Customers	Total Capacity (kW)	Battery Storage		Number of Customers	Total Capacity (kW)	Battery Storage	
			kW	kWh			kW	kWh
Jan	11	91.9			3	264.6		
Feb	2	45.6			10	78.7	13.5	27
Mar	1	300			4	31.7		
Apr	1	125			6	36.5	3.8	10.5
May	3	100			8	55.9	8.7	17.6
Jun	5	520			7	45.9		
Jul	2	31.4	20	19.4	9	70	5	10
Aug	6	638.7			6	28.4	3.8	10.5
Sep	0	0			1	6.4		
Oct	5	101.5			6	91.8		
Nov	1	500			4	43.3	10	20
Dec	6	1229.6			12	96.6	38.5	61.3
2024	43	3683.7	20	19.4	76	849.8	83.3	156.9
Cumulative	66	6267.3	24.5	28.4	159	1706.6	183.1	357.7

Figure 19A illustrates the total capacity for residential and non-residential, as well as the cumulative capacity.

Figure 19A. Excess Distributed Generation



Small Power Production

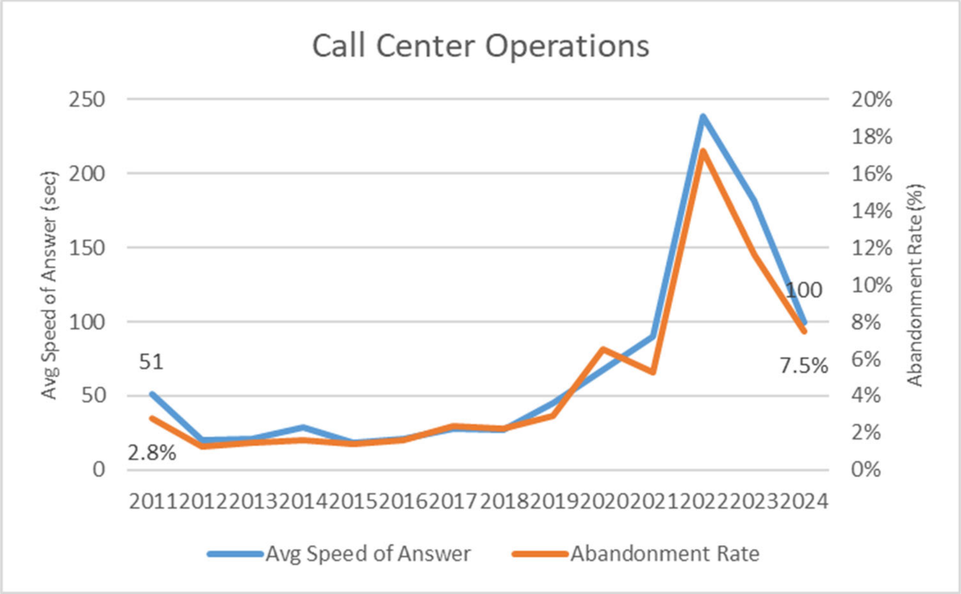
In 2024, NIPSCO had two customers added to Rider 578 – Purchases from Cogeneration Facilities and Small Power Production Facilities. Both customers are grocery stores and contracted for no capacity, with the intention to use the power generation onsite.

CUSTOMER SERVICE

NIPSCO's highest priority is the delivery of safe, reliable service to customers. NIPSCO strives to respond to the needs of its customers in the communities it serves across Northern Indiana. The Company regularly benchmarks and measures the success of its customer service efforts to continually improve on processes and scores.

Figure 20 shows NIPSCO's average speed of answer and abandonment rates.

Figure 20. Call Center Operations

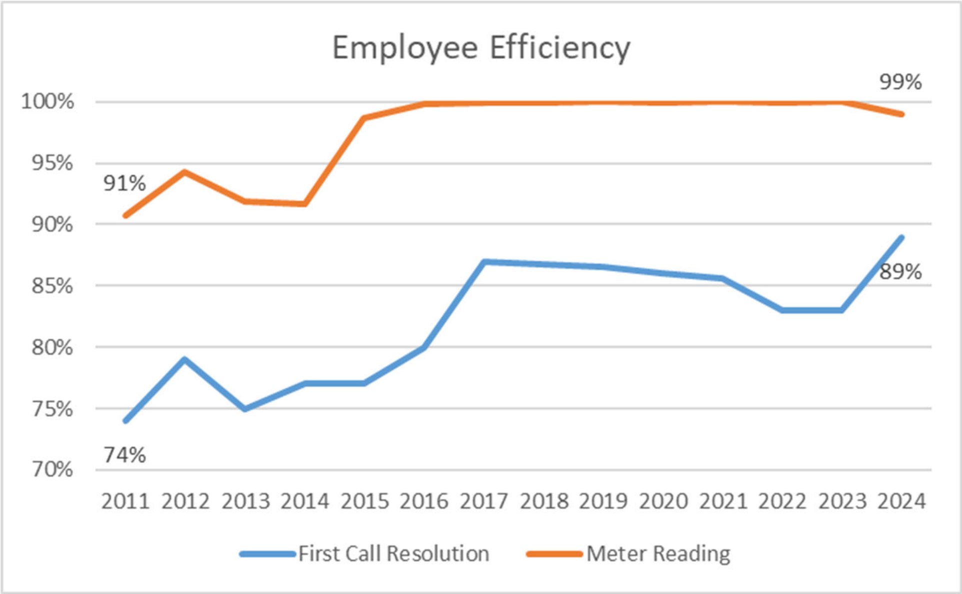


The average speed of answer ("ASA") metric represents the average number of seconds a caller waits before their call is answered by a Customer Service Representative ("CSR"), exclusive of the time a caller is navigating through the interactive voice response ("IVR") phone system. The decrease in ASA in 2023 was due to a reduction in calls routing to the CSR and improved attrition. NIPSCO saw a 12% reduction in call volume routing to a CSR due to customers becoming more accustomed to the IVR system, which was installed in 2022, therefore meeting their own self-service needs, an improvement in routing customers to make payments, and fuel costs stabilizing as 2023 progressed. This trend continued in 2024 with the ASA decreasing from 182 in 2023 to 100 in 2024.

The abandonment rate represents the percentage of telephone calls that are ended by customers before speaking with a CSR. The call center telephone system informs customers of their estimated wait time to speak to a CSR and gives them the option to receive a "virtual callback", in which Virtual Hold technology autodials the customer in the order that the customer called, whenever a CSR is available for the next caller. The abandonment rate decreased by 5.5% in 2023, for the same reasons noted above for the ASA improvement and decreased again in 2024 by 4.1%.

Figure 21 shows NIPSCO's first call resolution and meter reading rates. The customer satisfaction metrics shown in Figure 22 are both indirectly related to the two metrics shown in Figure 21.

Figure 21. Employee Efficiency



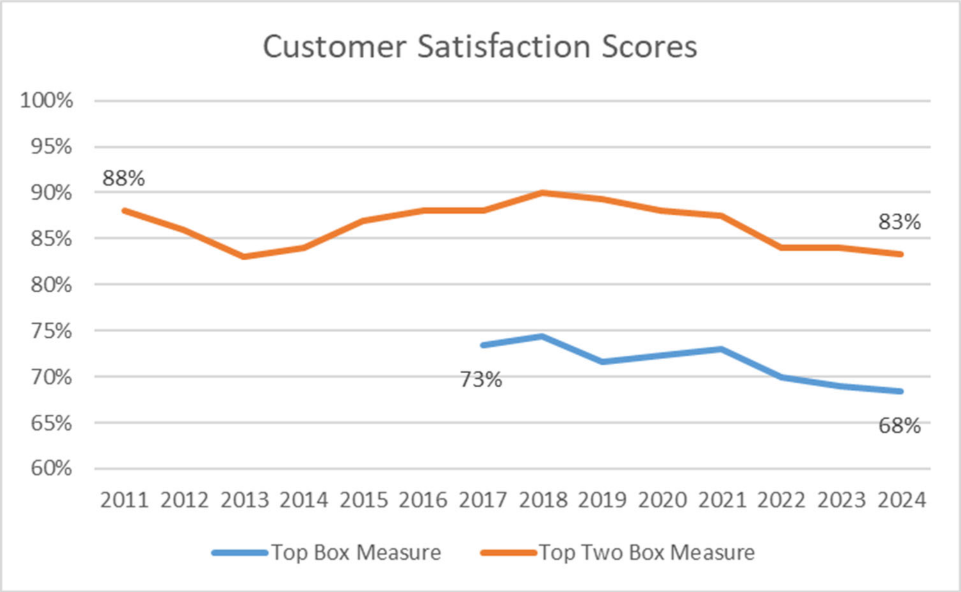
The first call resolution metric is measured by an outside vendor and represents how often NIPSCO is able to meet a customer's needs during the first telephone call. Customers highly value the ability of NIPSCO to resolve their issues quickly. NIPSCO continues to be above the 80% range for this metric, increasing from 83% in 2023 to 89% in 2024.

The meter reading metric represents the percentage of NIPSCO's residential and commercial electric meters that the Company accurately reads each month. The rollout of the Company's automated meter reader program in 2015 and 2016 accounts for the significant improvement in this area since 2014 and the transition to Electric Automated Metering Infrastructure (AMI) began in 2024.

Customer Satisfaction

Figure 22 shows NIPSCO's customer satisfaction scores. NIPSCO engages a third party to measure how well the Company interacts with its customers. The customer satisfaction (CSAT) score reflects the average customer experience when they interact with: (1) a CSR on the phone; (2) the IVR phone system; (3) an employee on the customer's property; or (4) NIPSCO's self-service website. NIPSCO's CSAT saw a decline in 2024, due to lower satisfaction with property restorations. The CSAT metric is inclusive of both gas and electric customer experience. NIPSCO incorporated the CSAT score into its corporate incentive plan calculation in 2017, as part of its commitment to customer service.

Figure 22. Customer Satisfaction Scores



In 2024, NIPSCO saw satisfaction increase over 2023 satisfaction, for the customer service representatives, the IVR (automated phone system), and the online self-service web experiences. However, NIPSCO saw a slight decline in satisfaction for field operations, specifically relating to property restorations. The decline in field operations satisfaction scores in 2024 was minor and was driven by limited communication and delays in property restoration after completed work. NIPSCO has engaged in a multi-year project, focused on improving the communication and property restoration process, which has included engaging with customers to better understand their expectations and receiving feedback for making improvements to the property restoration process.

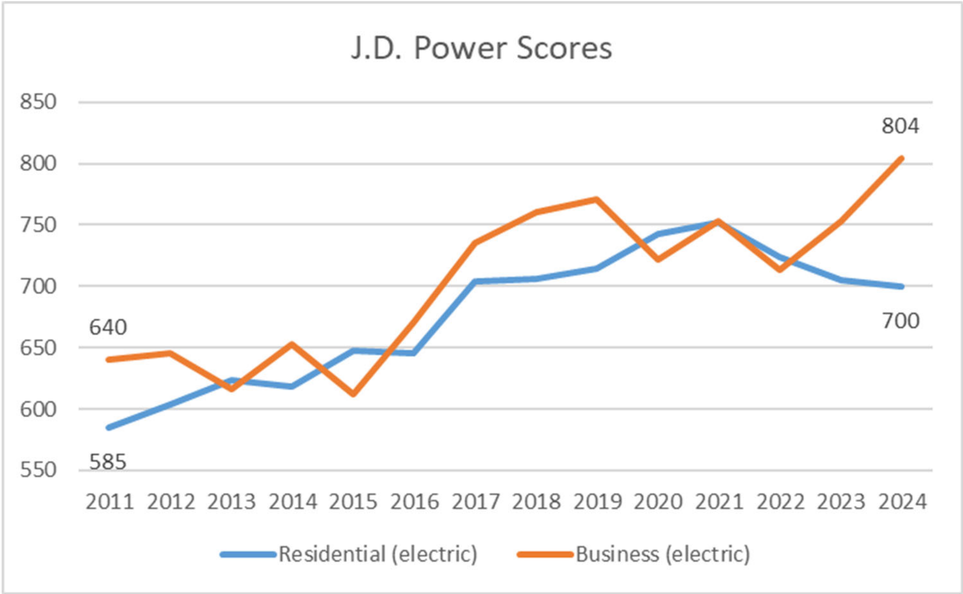
Prior to 2015, the CSAT score primarily reflected customers' interactions with NIPSCO's call center, and customers were only asked one question. The Company modified its satisfaction survey in 2015 to better measure its performance in discreet channels and weighted each channel's score according to the number of surveys completed for that channel. NIPSCO has found that measuring customer satisfaction in different channels better identifies successful practices and opportunities for improvement.

In 2017, NIPSCO retained a new vendor and made three significant changes to determining the CSAT score. First, customers were allowed to complete online surveys, whereas all surveys had previously been conducted over the telephone. Second, NIPSCO began weighting each communication channel equally in the CSAT score calculation. Third, the Company switched from quantitative responses (1-10) to qualitative responses (such as "I am somewhat satisfied").

In 2022, NIPSCO changed the standard of measurement for customer satisfaction to align with NIPSCO's goal of providing a top tier customer experience. Prior to 2022, customer satisfaction was measured and reported as a top-two box measure – very satisfied or somewhat satisfied. The reported score was the percentage of customers who responded within those two box measures. In 2022, the customer satisfaction metric was changed to a top-box metric – very satisfied. The reported score is now the percentage of customers who responded within the top box measure. So as not to skew the metric, Figure 22 illustrates the CSAT score for both calculations. NIPSCO does not have data available for the top-box measure prior to 2017.

Figure 23 illustrates the J.D. Power Electric Utility scores for residential and business customers. The J.D. Power Electric Utility Customer Satisfaction studies examine residential and business customer satisfaction across six factors – power quality and reliability, price, billing and payment, communications, corporate citizenship, and customer service. In 2024, NIPSCO saw an increase in overall satisfaction for business customers, while residential customer satisfaction decreased slightly from a peak high in 2021.

Figure 23. J.D. Power Scores



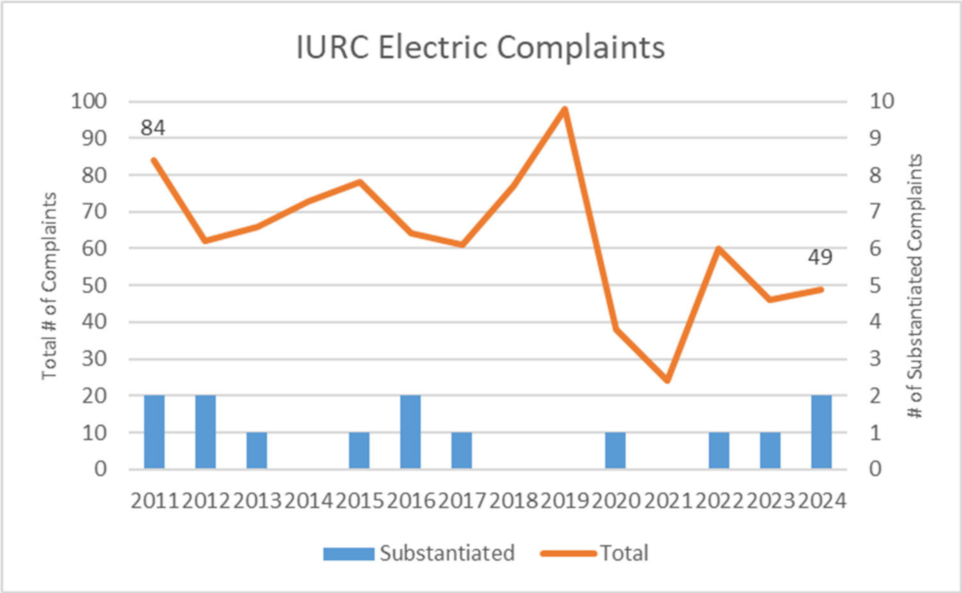
In demonstration of NIPSCO's improvement and overall focus on serving customers, the 2024 J.D. Power Residential Customer satisfaction survey for the Midwest region of midsize utilities scores NIPSCO at 700, which is above the group average of 692 and the highest of the three Indiana electric investor-owned utilities in the segment. In J.D. Power's Business Customer satisfaction survey, NIPSCO received a score of 804, which is above the group average of 779, and the highest out of Indiana's three electric investor-owned utilities in the segment.

While NIPSCO subscribes to the J.D. Power Business satisfaction survey and that is the main reporting metric in this report, additional input and feedback is needed from customers to help the Company identify key opportunities for improved customer service. The J.D. Power Business satisfaction survey is (1) a perception-based survey with slightly more than 100 NIPSCO Business customer respondents each year, many of whom may not have had a recent interaction with the Company, and (2) focused on small- to medium-sized businesses and is not a representative tool to gauge the satisfaction or opportunities for improvement related to NIPSCO's large customers.

In 2021, as part of its efforts to continue to enhance its relationship and service to commercial/industrial customers, NIPSCO hired an independent market research group (MSR Group) to survey NIPSCO's large business accounts on an annual basis, to help the Company focus its efforts related to this group of customers. This metric is based on customer satisfaction with NIPSCO account managers and improved from 81% in 2021 to 95% in 2023, remaining relatively flat for 2024 at 93.8%.

Figure 24 illustrates the number of electric complaints filed with the Commission against NIPSCO and the number of complaints that were substantiated. Utility customers in Indiana may file a complaint with the Commission if they feel aggrieved. The Commission's Consumer Affairs Division investigates each complaint and determines whether the complaint is substantiated. In 2024, NIPSCO received two substantiated complaints. The number of complaints came from a broad array of service category types.

Figure 24. IURC Electric Complaints



INVESTMENT AND SPENDING

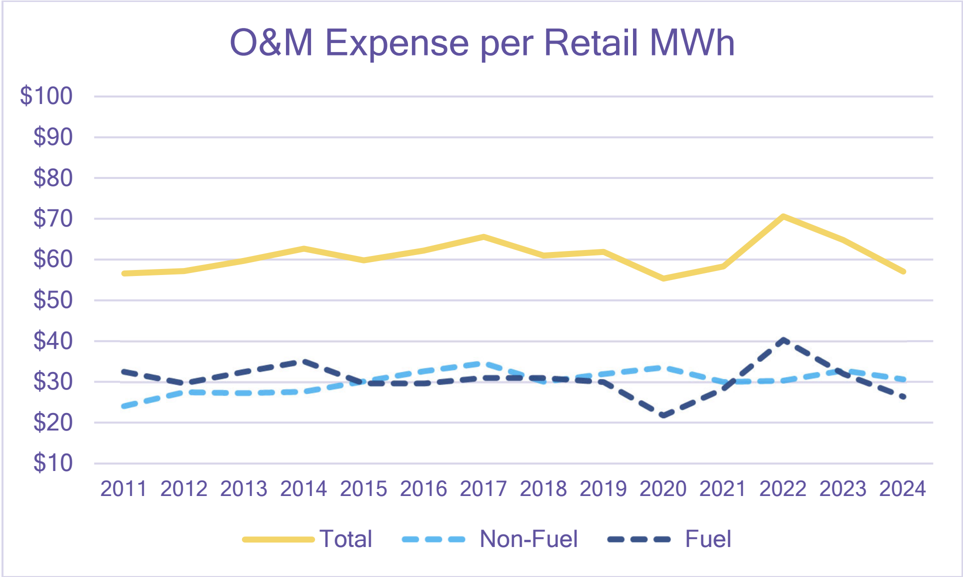
This section analyzes NIPSCO's operations and maintenance ("O&M") expense. The data is the same as the data included in NIPSCO's Federal Energy Regulatory Commission (FERC) Form 1.

The Electric O&M Expense section of NIPSCO's FERC Form 1 is divided into eight parts. Part 1 covers power production, which is divided into steam, nuclear, hydro, and other (gas). Parts 2-4 cover power delivery functions: transmission, regional market, and distribution. Parts 5-7 cover customer service and Part 8 covers corporate administration.

In this report, megawatt hours ("MWh") represent either retail sales (Figures 25, 26, 31, 32, 33, 34, and 35), or total sales including sales for resale (Figures 27, 28, 29, and 30), with the legends marked accordingly. Figure 27 also expresses non-fuel production O&M expense as a function of MWh generated by the utility. The "non-fuel" numerators exclude Accounts 501 (steam fuel), 547 (other generation fuel), and 555 (purchased power). Figure 28 also expresses transmission O&M expense as a function of line miles. These accounts can be found on pages 320 and 321 of NIPSCO's FERC Form 1.

Total O&M

Figure 25. O&M Expense per Retail MWh[9]



[9] FERC Form 1, Page 323, line 198 / Page 301, line 10 (d).

Figure 25 illustrates O&M expense per retail megawatt hour.

Figure 26. O&M Expense per Retail Customer[10]

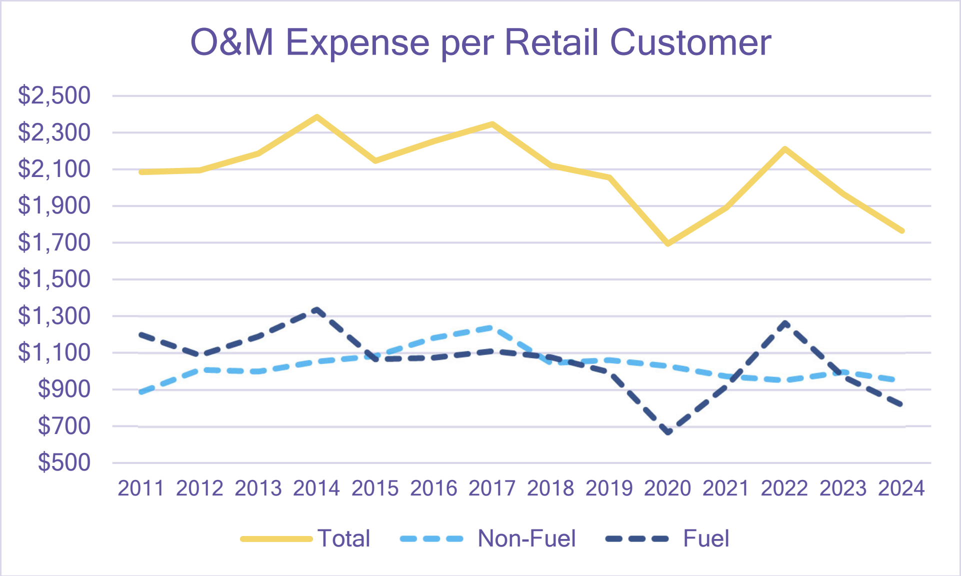


Figure 26 illustrates O&M expense per retail customer.

O&M Components

Figure 27. Non-Fuel Production O&M Expense[11]

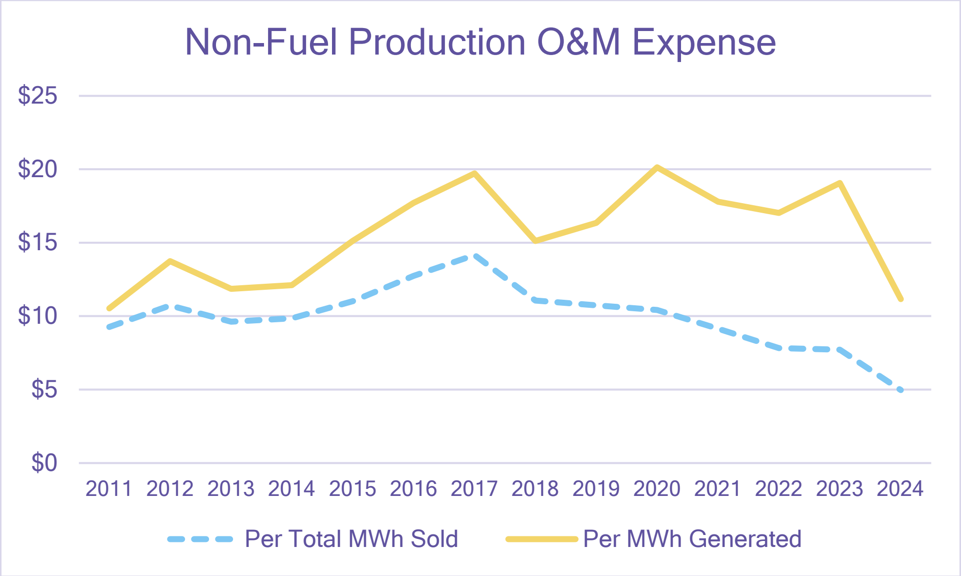


Figure 27 illustrates NIPSCO's non-fuel production O&M expense.

[10] FERC Form 1, Page 323, line 198 / Page 301, line 10(f).
[11] FERC Form 1, Page 321, line 80- lines 5, 25, 63, and 76 / Page 301, line 12(d); per MWh generated uses Page 401a. line 9.

Figure 28. Transmission and Distribution O&M Expense[12]

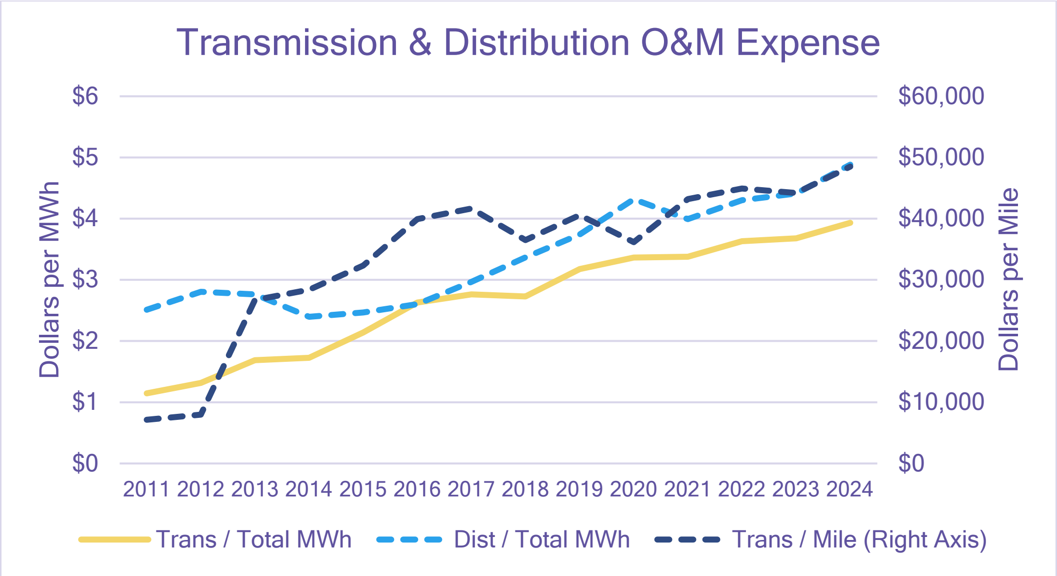


Figure 28 shows NIPSCO's transmission and distribution expenses as a function of total energy sales, and transmission expenses as a function of line miles. In 2013, NIPSCO reclassified its 69 kV circuit miles from transmission to distribution in accordance with FERC's seven-factor test.

The principal driver of transmission expense during this period has been Account 561.8, Reliability, Planning, and Standards Development Services. This account reflects the costs of three regional transmission expansion project (TEP) types that MISO has billed to NIPSCO through Schedule 26. The Commission authorized NIPSCO to begin recovering these costs through the utility's Regional Transmission Organization tracker (Rider 871) in 2012.

The largest component of distribution expense each year is Account 593, Maintenance of Overhead Lines, which has averaged greater than 50% of the total expenses in this category since 2013. The reliability section of this report discusses how NIPSCO's investment in vegetation management in recent years has positively affected its reliability indices.

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12 FERC Form 1, Transmission (Page 321 line 112); distribution (Page 322, line 156) / MWh (Page 301, line 12(d); per pole mile uses (Page 422, line 36).

Figure 29. Customer O&M Expense per Total MWh[13]

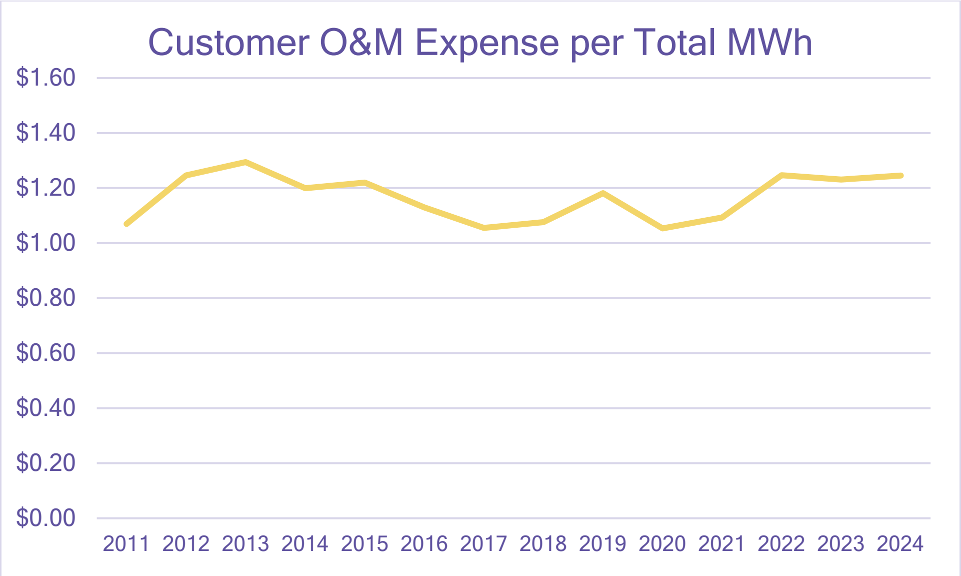


Figure 29 illustrates the customer O&M expense per total MWh. Customer expense accounts in FERC Form 1 are organized into three parts: customer accounts, customer service and information, and sales. Figure 29 illustrates the sum of these accounts divided by total sales. The decline in 2020 was mostly driven by changes in spending related to COVID-19 and by reduced load, and costs have since increased to levels slightly above those in 2019.

Administrative and General ("A&G") expenses are the final O&M component shown in FERC Form 1. This part includes accounts such as A&G salaries, office expenses, outside services employed, and employee pensions and benefits. These expenses are primarily fixed, meaning they do not rise and fall in the short run with changes in sales levels.

[13] FERC Form 1, Page 323, line 164 + line 171 + line 178 / Page 301, line 12(d).

Figure 30. A&G O&M Expense per Total MWh[14]

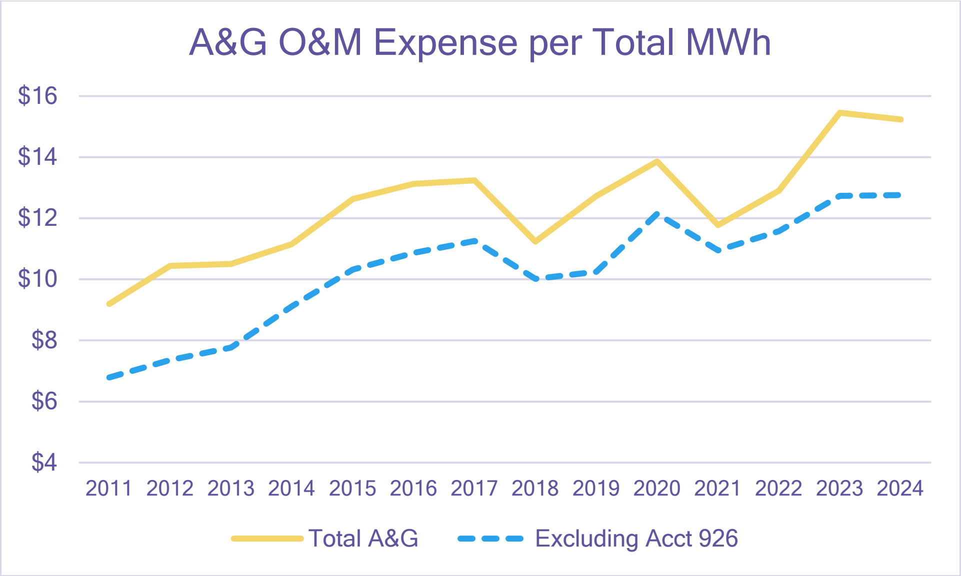
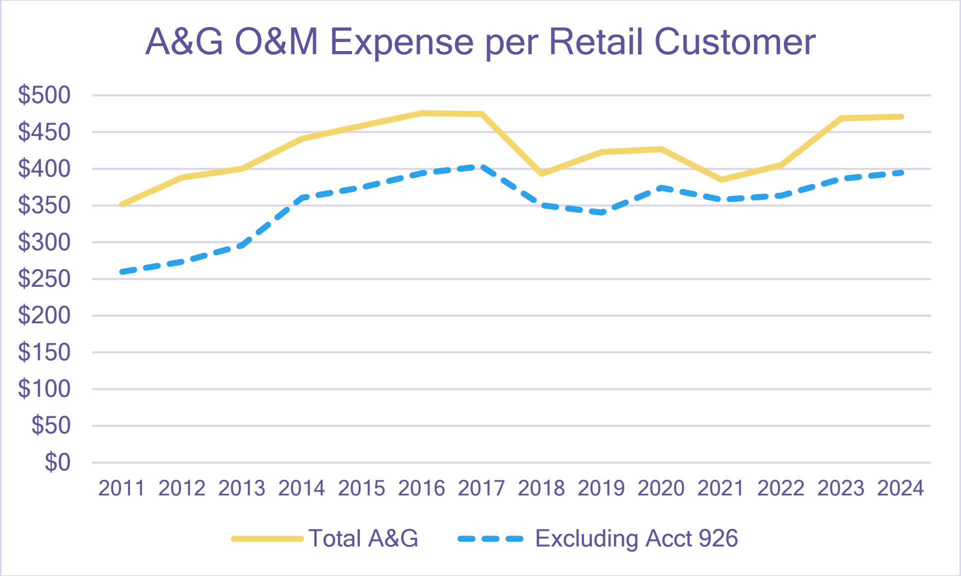


Figure 31. A&G O&M Expense per Retail Customer[15]



Figures 30 and 31 show A&G expenses as a function of total sales and retail customers. The figures also represent the metrics without Account 926, Employee Pensions and Benefits. This account is largely driven by interest rates and investment returns, two functions significantly outside of the utility's control.

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[14] FERC Form 1, Page 323, line 197 / Page 301, line 12(d); Acct 926 is Employee Pensions and Benefits expense (Page 323, line 187).
[15] FERC Form 1, Page 323, line 197 / Page 301, line 12(f); Acct 926 is Employee Pensions and Benefits expense (Page 323, line 187).

Benchmarking Analysis

This section illustrates the respective metrics of NIPSCO and the median Indiana electric investor-owned utilities against nationally comparable data. The data of the 20% of U.S. utilities with the lowest (best) metrics (i.e., the first quintile) is represented within the light blue section at the bottom of each graph. Each colored area above the first quintile represents a successive quintile.[16]

Figure 32. O&M Expense per Retail MWh

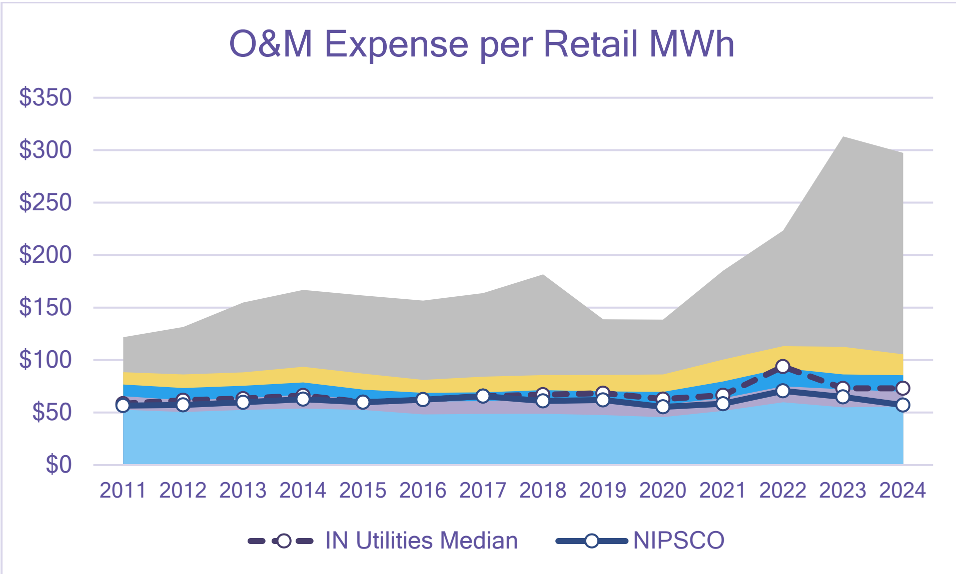
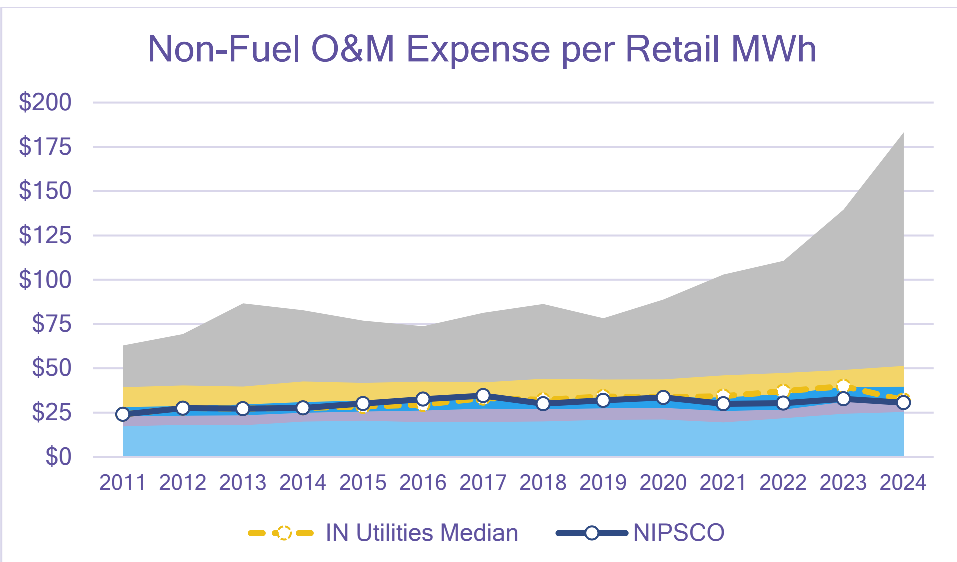


Figure 32 illustrates the O&M expense per retail megawatt hour.

Figure 33. Non-Fuel O&M Expense per Retail MWh



16 The 5th quintile (i.e., grey shaded area) represents the 95th percentile of U.S. utilities. The top 5% of U.S. utilities with the highest (worst performing) metrics are treated as outliers and not presented in the graphic.

Figure 33 illustrates the non-fuel O&M expense per retail megawatt hour.

Figure 34. Fuel O&M Expense per Retail MWh

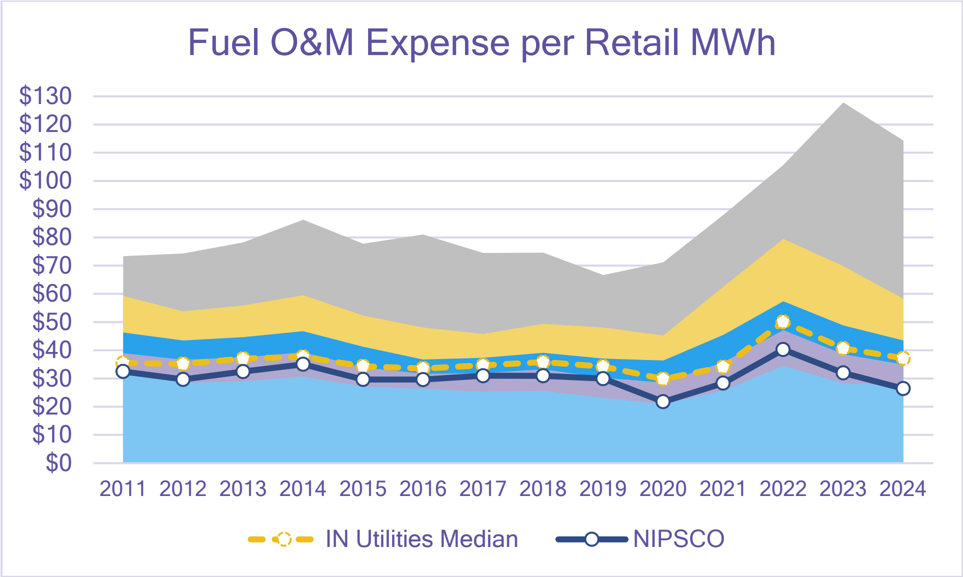


Figure 34 illustrates the fuel O&M expense per retail megawatt hour.

Figure 35. A&G O&M Expense (net of Acct 926) per Retail MWh

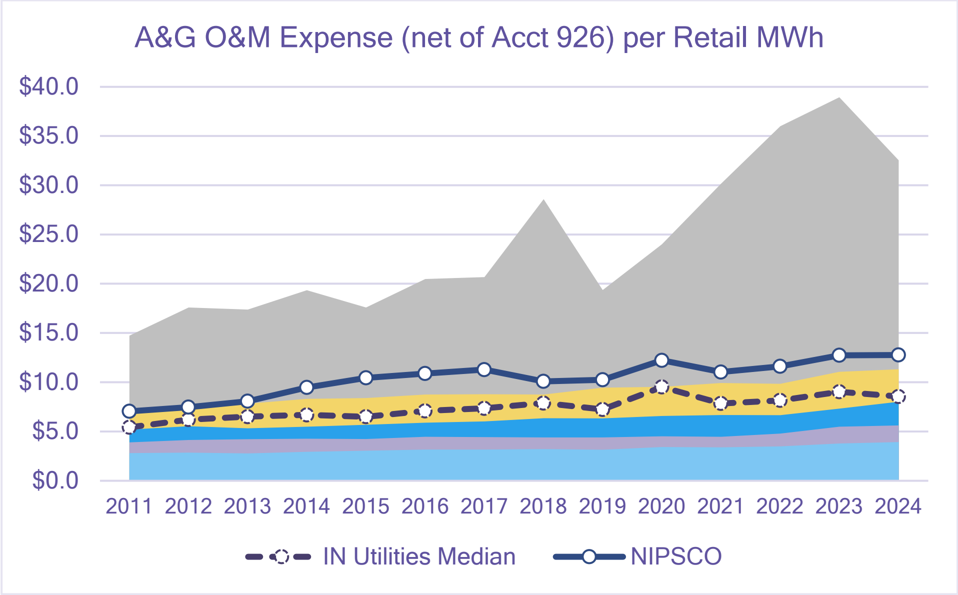


Figure 35 illustrates the A&G O&M expense (net of Acct. 926) per retail megawatt hour. The increase in 2020 was due to declining sales volumes related to COVID-19 and the implementation of Rate 831. A&G O&M expense (net of Acct. 926) per retail megawatt hour remained at the same level in 2024 compared to 2023.

AFFORDABILITY

Customer Bills

NIPSCO's most recent electric base rates went into effect on March 1, 2024.

Figure 36. Residential Bills[17]

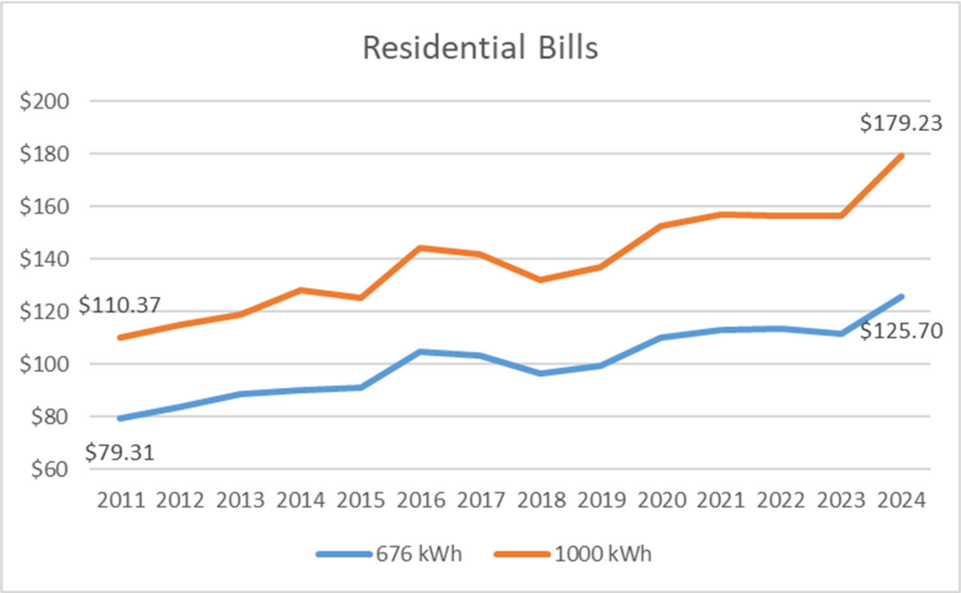


Figure 36 illustrates the average monthly bill for residential customers. NIPSCO's customers experienced a decrease in bills in 2018 primarily driven by the Tax Cuts and Jobs Act of 2017. The average monthly usage of NIPSCO's residential customers during the test year of the Company's most recent rate case, which established new rates, was 676 kWh. Residential bills experienced an increase due to a base rate case implemented March 1, 2024.

Figures 37 and 38 depict seven of the 15 demand and usage combinations that the Edison Electric Institute includes in its Typical Bills and Average Rates Report, which is published each winter.

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[17] The IURC calculates each utility's electric bill on July 1 each year and reports this information at https://www.in.gov/iurc/2761.htm. For consistency, the 676 kWh number reflects July 1, 2024, data as well.

Figure 37. Commercial Bills

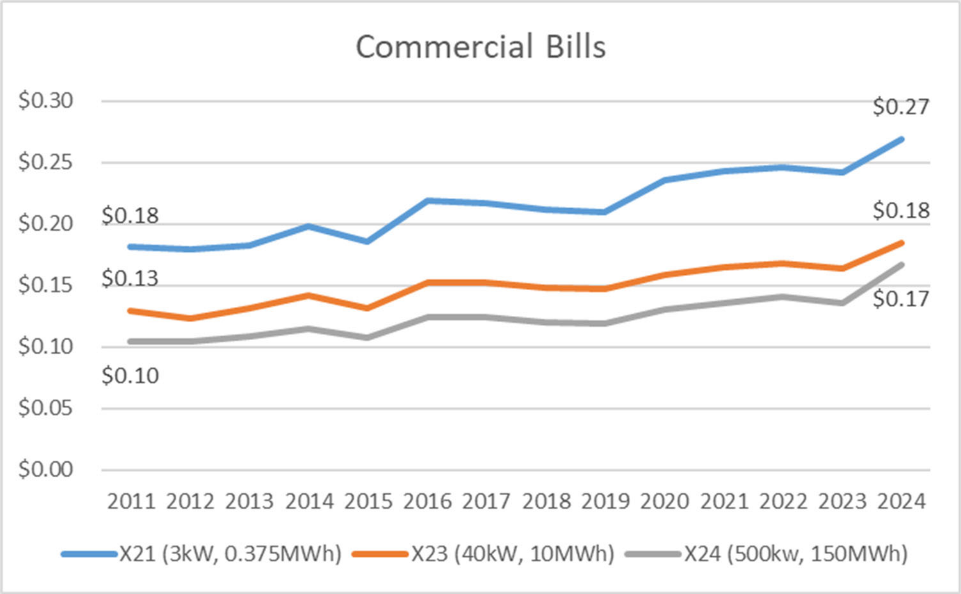

Figure 37 shows the average commercial bill per kilowatt hour. Rates increased due to a base rate case implemented March 1, 2024.

Figure 38. Industrial Bills[18]

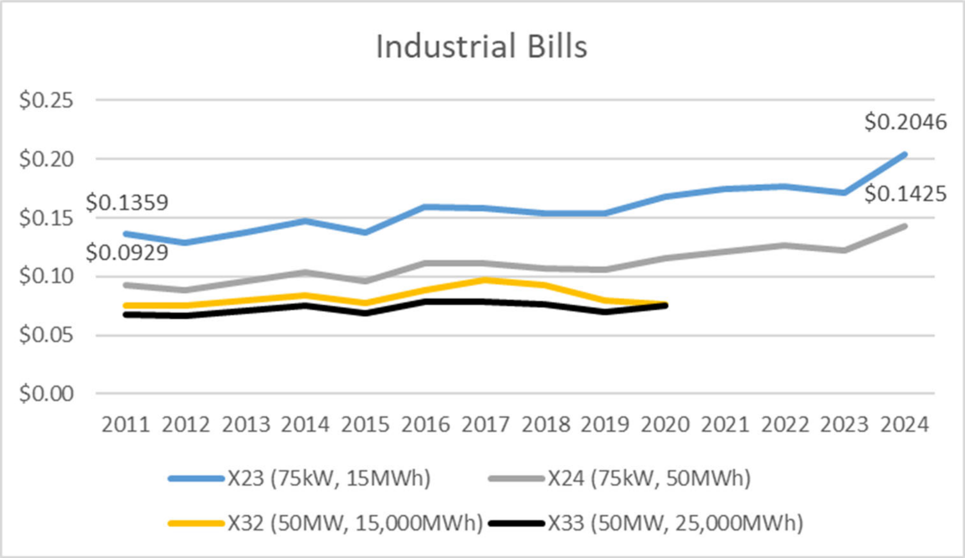

Figure 38 shows the average industrial bill per kilowatt hour. Rates increased due to a base rate case implemented March 1, 2024.

[18] Trendlines are not continued for Rate 832/833 data, due to changes to eligibility for these rates in 2020.

Figure 39. Industrial Bills[19]

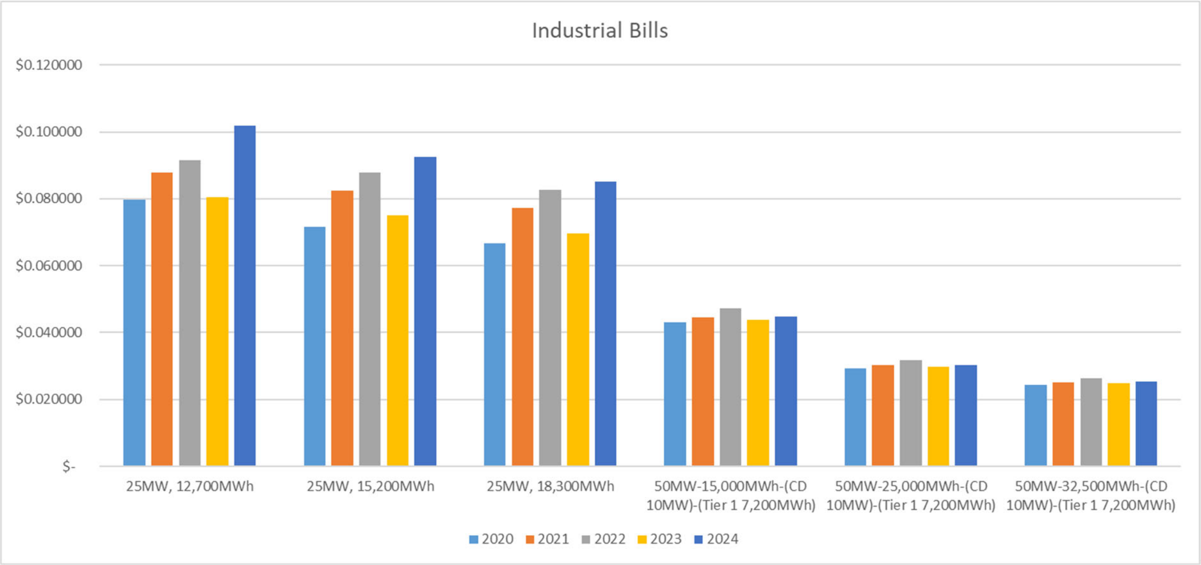

Figure 39 represents the average industrial bill for 500 Series Rates based upon the specific usage parameters. The chart is based upon the most appropriate 500 Series industrial rate for the specific usage parameters and the most appropriate rate may change over time based upon the rate design of Rates 531, 532, and 533. Rates increased due to a base rate case implemented March 1, 2024.

On January 1, 2020, NIPSCO implemented new base rates, including the introduction of a new industrial rate structure. NIPSCO's Electric Rate 531, Industrial Power Service – Large is available to Industrial Customers taking service at Transmission (> 69,000 volts) or Subtransmission voltage (34,500 volts). Customers contract for a definitive amount of electrical demand, which cannot be less than 10,000 kW. The rate also offers aggregation of premises held under common ownership and having the same qualifying service voltage.

Tier 1 is a traditional firm utility service. The default Tier 1 Contract Demand is 30,000 kW, with an option to elect above or below the default amount, down to 10,000 kW. Tier 1 includes a demand charge. Tier 1 firm energy is calculated on an hourly basis and is subject to Tier 1 energy charges, transmission charges, and applicable Riders.

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[19] Rate 531 does not include Tier 2 and/or Tier 3 energy charges and costs to obtain Tier 2 and/or Tier 3 capacity.

The implementation of Rate 531 reduced NIPSCO's sales volumes, which impacts a variety of metrics. NIPSCO will continue to monitor the various metrics and is committed to working with stakeholders on the best way to illustrate Rate 531 and its influence on the various metrics.

NIPSCO regularly optimizes the customer's demand and energy based on the current rate structure. The optimal rate for 25MW demand and 12,700 MWh energy usage has historically been with the 532 rate class. However, in 2023, the optimal rate for 25MW demand and 12,700 MWh changed to rate 533. Therefore, NIPSCO has removed rate classes associated with each scenario in Figure 39 and is presenting the optimal rate based on historic actual rates with the defined scenarios.

Service Disconnections

Figure 40. Residential Service Disconnections

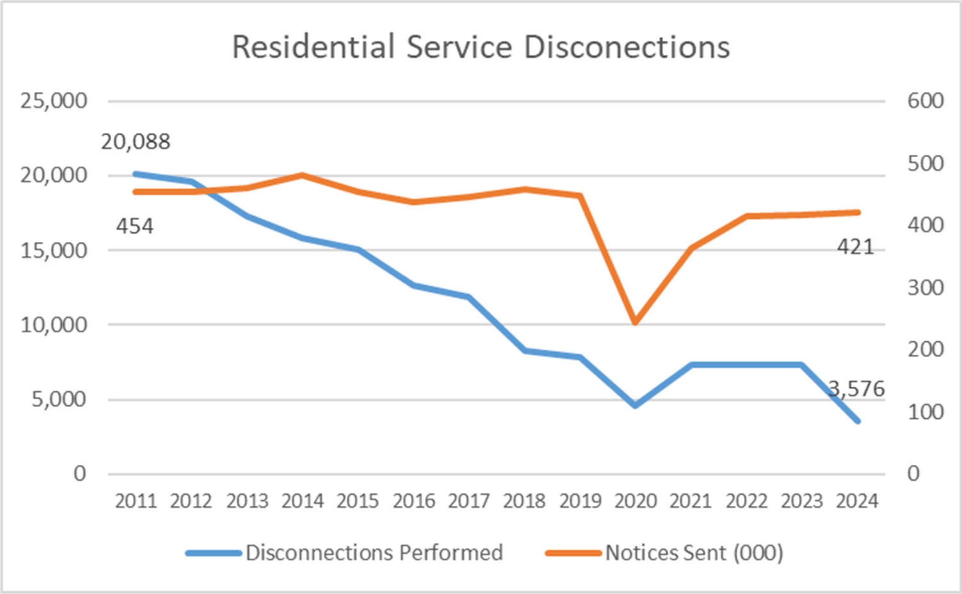


Figure 40 illustrates the number of notices sent to residential customers regarding disconnection for non-payment and the number of disconnections performed. NIPSCO sends a notice of disconnection to a customer 12 days after the customer's bill is due. NIPSCO continues to work with customers who have accounts that are in arrears, by initiating telephone calls to facilitate payment arrangements. As a result, fewer orders for disconnection are sent to the field. NIPSCO continues its program, launched in 2018, that allows customers to make payments over the telephone, while the technician is on-site to complete the disconnection, thereby providing a final opportunity for a customer to avoid disconnection. These efforts have led to a decrease in disconnections for non-payment in recent years, compared to earlier years.

NIPSCO has continued to work with customers to make payments manageable. NIPSCO has various payment plans that range from three months up to 12 months to help customers who are struggling to stay current on their utility bills. NIPSCO has experienced an increase in customer participation in these payment plans. In 2022, NIPSCO enhanced its website functionality to allow customers to enroll in payment plans online. The Company encourages customers to sign up for budget billing, to keep payments consistent throughout the year, and promotes energy efficiency programs, to help customers reduce usage. Finally, in 2023, NIPSCO implemented a pro-active billing and payment communication program for residential customers, to assist in bill and arrears management. This proactive communication is provided via text, email, and phone calls.

Figure 41. Average Residential Accounts in Arrears at Least 60 Days

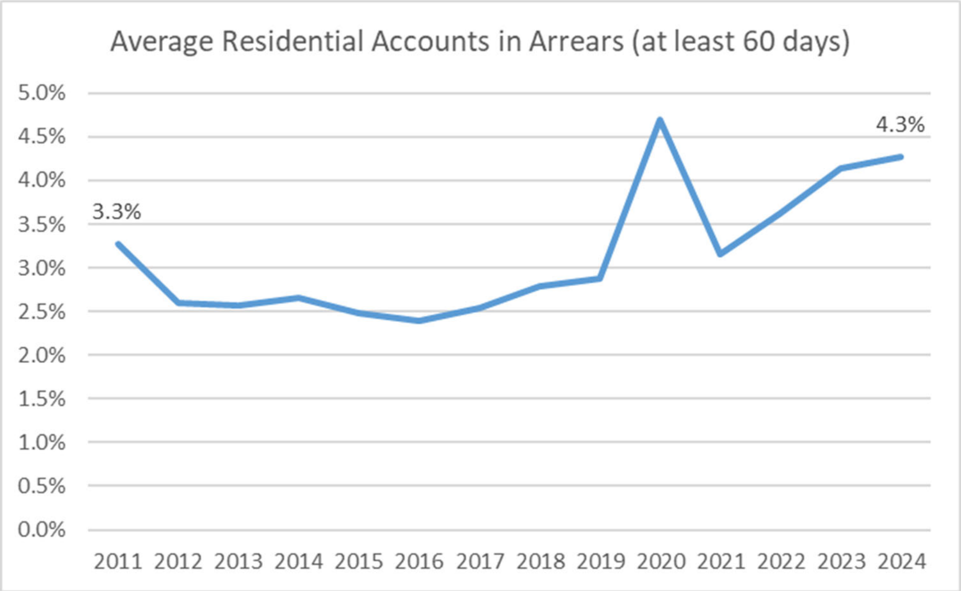


Figure 41 illustrates the average percentage of residential accounts in arrears at least 60 days. In 2024, residential accounts in arrears increased slightly compared to the previous year, due to various economic factors.

STAFFING

Figure 42. Employee Turnover

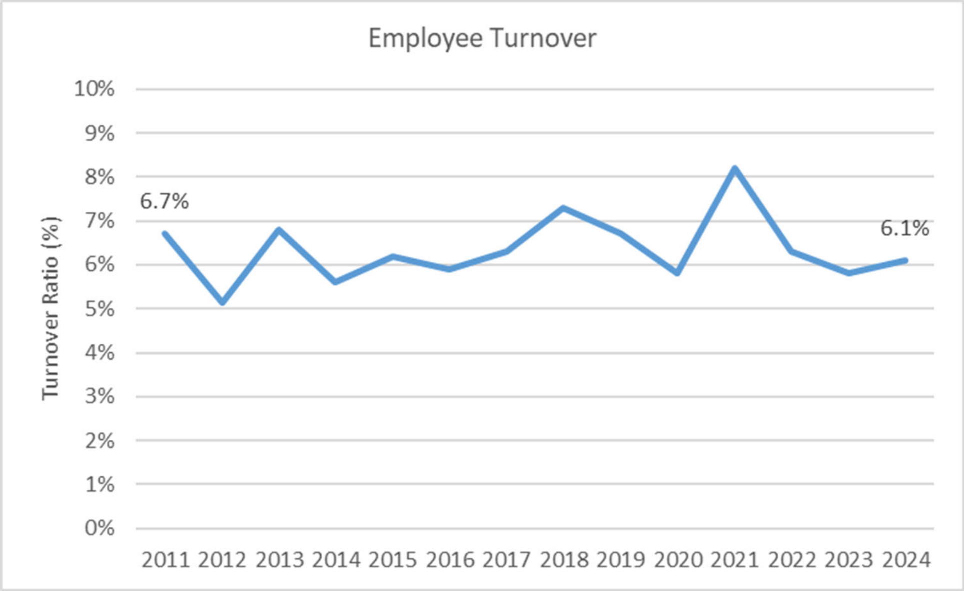
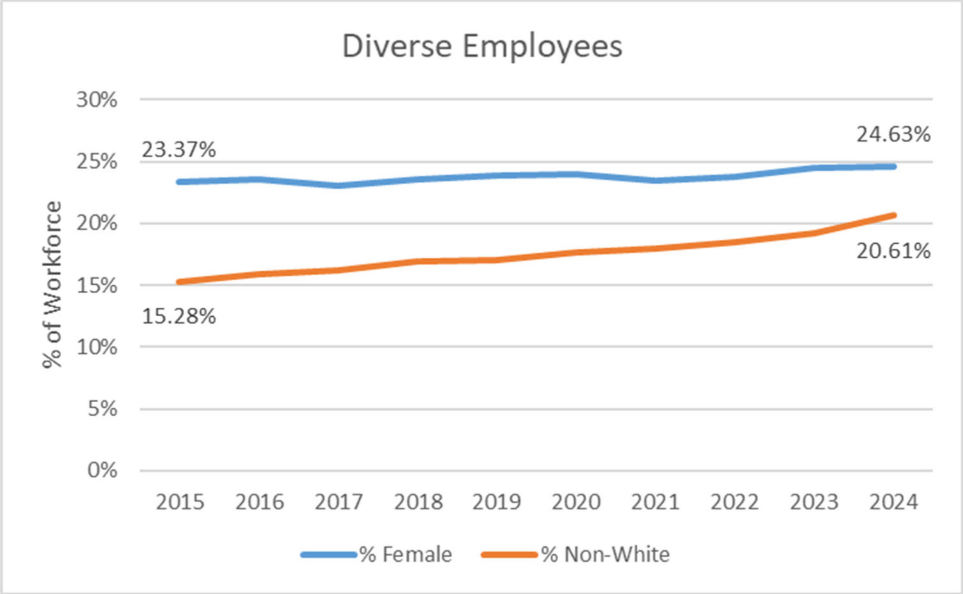


Figure 42 shows NIPSCO's employee turnover ratio, which is calculated using the average number of employees during the year. In 2021, NIPSCO saw a significant uptick in turnover due to voluntary departures, including retirements. The overall decrease in employee turnover at NIPSCO in 2022 and 2023 was due to a significant decline in retirements. There was a slight increase in employee turnover in 2024 due to retirements and discharges.

Figure 43. Diverse Employees



Since 2015, NIPSCO has been depicting data, as shown in Figure 43, concerning the diversity of its employees. In 2024, around 25% of NIPSCO's workforce comprised females, while 21% were non-white. NIPSCO maintains a dedication to fostering and preserving a diverse and capable workforce. Inclusivity and diversity extend beyond race or gender, encompassing a range of perspectives, life experiences, cultures, abilities, generations, sexual orientations, and other attributes. This commitment constitutes an ongoing, strategic endeavor integrated into the company's operational framework.

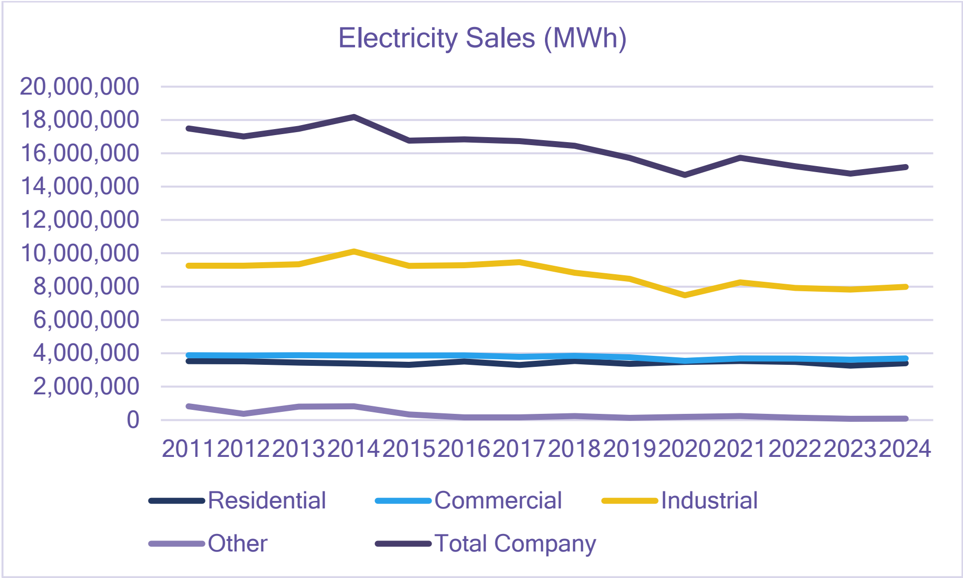
NIPSCO is committed to providing equal employment opportunities to all employees and applicants, regardless of race, color, religion, national origin or ancestry, veteran status, disability, gender, age, marital status, sexual orientation, gender identity, genetic information, or any legally protected group status. Each employee is expected to uphold this commitment and abide by these principles. Additionally, NIPSCO strives to ensure that its employees and leaders have a deep understanding of cultural issues while promoting the company's inclusive brand within the communities it serves.

CONCLUSION

NIPSCO continues to focus on safety, reliability, customer service, investment and spending, and affordability. In 2024, NIPSCO saw improvements in several areas and laid plans for additional improvements. The common theme in all areas is NIPSCO's commitment to its customers. NIPSCO will strive to continue to improve its reliability metrics and maintain its focus on vegetation management. In addition, the Company recognizes the importance of providing excellent customer service and maintaining affordability, through rates, investments, and spending. One key to achieving all of these goals is continued employee engagement. NIPSCO appreciates the opportunity to review these metrics with its stakeholders, as it provides valuable input into the process of continued improvement.

APPENDIX

Usage Trend by Customer Class[20]



Usage by Customer Class (MWh)

Year	Residential	Commercial	Industrial	Public St & Hwy Other Auth, Rails	Interdept.	Sales for Resale	Total Company
2011	3,526,537	3,886,490	9,257,587	100,190	65,334	651,298	17,487,436
2012	3,524,316	3,863,067	9,250,976	99,172	19,924	250,843	17,008,298
2013	3,444,738	3,881,913	9,339,677	99,809	32,199	669,675	17,468,011
2014	3,384,222	3,864,241	10,114,222	103,424	44,695	675,484	18,186,288
2015	3,309,929	3,866,823	9,249,137	105,161	32,544	194,833	16,758,427
2016	3,514,821	3,878,747	9,281,765	103,797	33,066	18,998	16,831,194
2017	3,301,699	3,793,472	9,469,711	100,783	27,385	32,514	16,725,564
2018	3,535,168	3,844,574	8,829,536	96,557	27,837	114,268	16,447,940
2019	3,369,471	3,760,342	8,466,135	89,339	27,893	8,132	15,721,312
2020	3,483,963	3,550,025	7,480,320	82,070	23,928	83,548	14,703,854
2021	3,546,813	3,698,032	8,253,705	79,140	29,318	124,652	15,731,660
2022	3,482,939	3,682,376	7,915,344	69,919	19,564	49,973	15,220,115
2023	3,262,923	3,614,248	7,820,276	63,680	15,218	861	14,777,206
2024	3,404,882	3,697,947	7,984,846	70,487	14,698	-	15,172,860

[20] 'Other' category includes Interdepartment, Public Street & Highway, Other Authority, Rails, and Sales for Resale

2024 Appendix Data

	Fig.	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Safety															
Preventable vehicle crash rate	1	5.10	3.26	2.28	2.14	2.43	1.76	1.84	1.97	2.85	1.91	2.47	2.10	1.51	1.72
OSHA recordable incident rate	2	2.61	2.70	1.57	1.41	2.20	2.23	1.29	2.23	2.70	2.61	1.79	1.38	1.29	1.38
DART		1.01	1.60	1.08	0.97	1.18	1.37	0.61	1.61	1.95	1.59	1.69	0.85	0.77	0.89
OSHA rate NIPSCO w/BSA	3	2.61	1.83	1.5	1.26	1.23	1.2	0.75	1.14	1.33	1.24	1.20	0.82	0.70	0.85
DART - NIPSCO with BSA		1.1	1.04	0.93	0.84	0.65	0.61	0.33	0.68	0.88	0.75	1.04	0.54	0.44	0.58
Underground damages	4	3.48	4.50	3.73	3.11	3.00	2.56	0.258	0.209	0.22	0.121	0.182	0.082	0.099	0.043
Reliability															
Major event days	5A	7	5	6	7	3	4	2	5	8	5	10	9	6	5
Assoc. restor. days		15	12	8	11	5	6	2	7	14	8	11	15	14	6
Tree-related Outages (MED)	5B			5073	5605	4664	4275	4027	4403	4526	4488	5210	4679	3546	3853
Tree-related Outages (non-MED)				3261	3455	3925	3705	3610	3595	2933	2875	3233	2815	2624	2936
TMED (minutes)		11.8	11.5	9.4	8.2	9.5	8.7	8.2	7.9	7.8	8.5	8.6	9.3	9.3	9.3
SAIDI (MED)	6/7	371	428	524	603	248	231	153	244	359	473	529	370	320	534
(non-MED)		156	137	116	109	128	141	131	151	155	138	175	143	149	169
SAIFI (MED)	6/7	1.38	1.44	1.46	1.53	1.16	1.26	1.11	1.33	1.58	1.26	1.55	1.44	1.14	1.34
(non-MED)		1.03	0.95	0.84	0.89	0.93	1.01	1.01	1.09	1.07	0.901	1.058	0.95	0.87	0.96
CAIDI (MED)	6/7	269	297	359	395	214	184	138	184	227	374	341	257	281	399
(non-MED)		151	145	138	122	137	139	130	139	145	153	165	150	171	175
Power Generation															
Generating unit capacity	8A	**Make updates on Figure 8A tab.**													
EAF	9														
		89.88%	81.20%	64.72%	86.10%	55.36%	53.63%	45.38%	63.45%	49.30%	62.17	57.42%	48.97%	70.70%	58.37%
		70.81%	82.09%	92.36%	78.74%	70.13%	75.29%	63.93%	42.23%	Retired	Retired	Retired	Retired		
		74.38%	75.95%	84.12%	69.15%	67.23%	57.44%	66.03%	0.00%						
		69.14%	76.55%	74.21%	77.99%	69.18%	74.89%	87.62%	61.41%	51.44%	45.21	0.00%	Retired		
		75.66%	81.72%	73.63%	66.22%	87.36%	80.75%	55.15%	80.28%	62.94%	48.79	44.58%	Retired		
		91.84%	74.69%	86.52%	81.48%	74.99%	89.12%	67.84%	87.24%	79.62%	82.13	68.29%	47.26%	58.44%	71.38%
		75.99%	96.97%	94.11%	75.52%	87.18%	60.40%	92.60%	67.51%	79.45%	73.57	57.80%	59.21%	72.84%	59.15%
		79.01%	*81.22%*	*79.25%*	*76.40%*	*73.15%*	*69.91%*	*67.74%*	*66.64%*	*63.24%*	*61.06%*	*46.44%*	*51.58%*	*67.60%*	*62.60%*
		88.56%	95.27%	91.81%	93.71%	78.90%	96.28%	91.00%	73.29%	88.90%	81.38%	91.95%	89.18%	68.69%	84.83%
EFOR	10/11														
		5.14%	1.17%	6.59%	1.09%	0.47%	16.25%	6.68%	24.36%	15.05%	22.88%	16.86%	41.85%	19.27%	36.68%
		7.47%	1.88%	3.95%	3.45%	20.69%	8.32%	15.77%	56.01%	Retired	Retired	Retired	Retired		
		7.48%	7.81%	4.92%	8.78%	13.20%	22.01%	17.00%	100.00%						
		3.20%	19.26%	10.52%	19.02%	32.89%	51.25%	17.94%	20.80%	39.83%	88.14%	100.00%	Retired		
		9.61%	13.12%	1.76%	11.03%	5.62%	15.46%	17.29%	19.08%	23.28%	59.74%	40.89%	Retired		
		7.50%	7.01%	5.20%	10.29%	0.66%	6.16%	12.75%	6.15%	10.90%	8.49%	18.23%	52.53%	34.76%	24.15%
		4.11%	1.55%	0.19%	4.89%	2.69%	6.57%	2.60%	11.19%	15.21%	13.95%	39.33%	36.27%	32.33%	33.38%
		6.36%	*7.43%*	*4.46%*	*8.28%*	*7.78%*	*16.54%*	*11.14%*	*19.66%*	*21.24%*	*40.27%*	*44.02%*	*43.68%*	*28.13%*	*31.71%*
		0.96%	1.66%	1.89%	0.41%	2.43%	0.82%	1.54%	5.93%	5.33%	6.00%	4.57%	1.05%	3.72%	6.29%
Net capacity factor	12														
		72.10%	56.82%	49.25%	66.67%	40.17%	41.30%	31.41%	51.19%	26.12%	37.85%	37.17%	35.52%	35.80%	23.13%
		56.95%	44.48%	52.61%	53.50%	48.89%	53.58%	47.61%	36.58%	Retired	Retired	Retired	Retired		
		60.38%	41.73%	54.68%	50.35%	26.98%	36.44%	31.33%	0.00%						
		52.58%	27.12%	40.83%	40.20%	13.21%	12.21%	17.00%	38.98%	32.20%	4.65%	-0.039%	Retired		
		59.41%	55.92%	54.02%	47.28%	45.04%	24.13%	20.25%	51.59%	37.62%	18.16%	34.67%	Retired		
		47.18%	30.42%	41.62%	65.64%	38.81%	49.30%	39.76%	55.00%	39.79%	29.61%	38.88%	32.65%	26.52%	28.05%
		52.06%	51.13%	71.35%	63.88%	56.69%	44.11%	70.27%	44.64%	46.06%	26.07%	36.12%	34.88%	22.43%	25.49%
		57.80%	*44.54%*	*51.63%*	*55.30%*	*37.64%*	*35.02%*	*34.62%*	*45.05%*	*35.76%*	*23.03%*	*29.36%*	*34.45%*	*28.85%*	*25.36%*
		46.64%	64.18%	50.98%	45.81%	68.41%	78.33%	73.79%	61.15%	75.91%	68.75%	59.14%	69.41%	60.62%	83.00%
	13										40.95%	35.50%	37.52%	32.20%	35.20%
												25.25%	31.82%	30.80%	34.90%
	14													17.80%	22.40%
														18.20%	21.20%
															22.27%
Gross Energy Availablity (GEA)															
	15										87.00%	94.59%	92.47%	88.80%	93.80%
												74.80%	83.78%	91.30%	96.10%
														86.70%	N/A
														85.20%	N/A
Solar Net Performance Ratio (NPR)	16														
														91.00%	84.00%
														84.80%	80.80%
															82.79%
Technical Energy Availability (TEA)															
	17										87.00%	95.64%	96.21%	91.10%	96.60%
												95.50%	92.01%	97.90%	98.50%
														89.10%	N/A
														87.50%	N/A
Distributed Generation															
Customer Satisfaction															
Avg speed of answer (sec)	20	51	20	21	29	18	21	28	27	45	68	90	239	182	100
Abandonment rate		2.8%	1.3%	1.5%	1.6%	1.4%	1.6%	2.3%	2.2%	2.9%	6.5%	5.3%	17.2%	11.6%	7.5%
First call resolution	21	74%	79%	75%	77%	77%	80%	87%	87%	87%	86%	86%	83%	83%	89%
Meter reading		91%	94%	92%	92%	99%	100%	100%	100%	100%	100%	100%	100%	100%	99%
Customer survey	22	88%	86%	83%	84%	87%	88%	88%	90%	89%	88%	88%	84%	84%	83%
J.D. Power scores	23														
		585	604	624	618	648	645	704	706	714	743	752	724	705	700
		640	645	616	653	612	671	735	760	771	722	753	713	753	804
Complaints to regulator	24														
		2	2	1	0	1	2	1	0	0	1	0	1	1	2
		84	62	66	73	78	64	61	77	98	38	24	60	46	49
		82	60	65	73	77	62	60	77	98	37	24	59	45	47

	Fig.	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
O&M Expenses															
O&M per MWh (total)		$56.57	$57.19	$59.70	$62.67	$59.79	$62.21	$65.59	$61.00	$61.89	$55.35	$58.31	$70.63	$64.79	$57.06
(non-fuel)		$24.09	$27.52	$27.26	$27.63	$30.14	$32.59	$34.59	$30.04	$31.93	$33.56	$29.97	$30.35	$32.81	$30.64
O&M per customer (total)		$2,084	$2,095	$2,186	$2,386	$2,146	$2,254	$2,346	$2,120	$2,055	$1,695	$1,891	$2,211	$1,966	$1,764.55
(non-fuel)		$888	$1,008	$998	$1,052	$1,082	$1,181	$1,237	$1,044	$1,060	$1,028	$972	$950	$995	$947.47
Non-fuel production O&M															
		$9.27	$10.73	$9.63	$9.85	$11.02	$12.74	$14.17	$11.06	$10.73	$10.42	$9.14	$7.82	$7.71	$4.97
		$10.53	$13.74	$11.86	$12.11	$15.13	$17.71	$19.72	$15.11	$16.35	$20.14	$17.78	$17.02	$19.06	$11.16
Transmission per MWh		$1.15	$1.31	$1.69	$1.73	$2.14	$2.63	$2.76	$2.73	$3.17	$3.36	$3.38	$3.63	$3.68	$3.93
Transmission per pole mile		$7,161	$7,985	$26,699	$28,367	$32,333	$39,913	$41,638	$36,477	$40,575	$36,159	$43,193	$44,913	$44,170	$48,510.57
Distribution expense per MWh		$2.51	$2.80	$2.76	$2.40	$2.47	$2.60	$2.97	$3.37	$3.74	$4.32	$3.99	$4.30	$4.41	$4.88
Customer operations per MWh		$1.07	$1.25	$1.29	$1.20	$1.22	$1.13	$1.05	$1.08	$1.18	$1.05	$1.09	$1.25	$1.23	$1.25
A&G per MWh		$9.20	$10.44	$10.50	$11.15	$12.63	$13.13	$13.24	$11.24	$12.72	$13.86	$11.78	$12.90	$15.45	$15.23
		$6.79	$7.36	$7.76	$9.12	$10.32	$10.86	$11.26	$10.01	$10.24	$12.15	$10.95	$11.57	$12.73	$12.76
A&G per customer		$352	$388	$400	$441	$459	$476	$474	$393	$423	$427	$385	$405	$469	$471.07
		$260	$274	$296	$361	$375	$394	$403	$351	$340	$374	$358	$364	$386	$394.66
Benchmarking															
O&M expense per retail MWh															
		$53	$51	$52	$54	$52	$48	$49	$49	$48	$46	$52	$60	$55	$ 55.98
		$65	$62	$64	$67	$62	$61	$61	$63	$62	$58	$63	$75	$72	$ 69.78
		$77	$73	$75	$79	$72	$69	$69	$71	$70	$70	$80	$92	$86	$ 85.50
		$88	$86	$88	$94	$87	$81	$84	$86	$86	$86	$100	$113	$111	$ 105.50
		$58	$62	$63	$66	$60	$62	$66	$67	$68	$63	$66	$94	$73	$ 73.00
		$57	$57	$60	$63	$60	$62	$66	$61	$62	$55	$58	$71	$65	$ 57.06
O&M (non fuel) per retail MWh															
		$17	$18	$18	$20	$20	$20	$20	$20	$21	$21	$19	$22	$24	$ 25.45
		$23	$23	$24	$25	$26	$26	$27	$27	$27	$28	$26	$27	$31	$ 32.14
		$28	$29	$30	$31	$32	$32	$33	$32	$34	$34	$34	$35	$39	$ 39.70
		$39	$40	$40	$43	$42	$43	$42	$44	$44	$44	$46	$47	$49	$ 51.40
		$24	$28	$27	$28	$28	$30	$33	$32	$34	$34	$34	$37	$40	$ 32.07
		$24	$28	$27	$28	$30	$33	$35	$30	$32	$34	$30	$30	$33	$ 30.64
A&G (less Acct 926) per MWh															
		$2.81	$2.86	$2.77	$2.94	$3.04	$3.16	$3.16	$3.21	$3.15	$3.43	$3.38	$3.48	$3.77	$3.92
		$3.89	$4.14	$4.22	$4.27	$4.22	$4.47	$4.43	$4.39	$4.39	$4.50	$4.46	$4.79	$5.48	$5.63
		$5.20	$5.53	$5.32	$5.48	$5.69	$5.88	$6.03	$6.34	$6.33	$6.57	$6.67	$6.65	$7.32	$8.03
		$7.34	$7.50	$7.83	$8.31	$8.39	$8.74	$8.78	$8.74	$9.44	$9.53	$9.92	$9.84	$11.05	$11.33
		$5.42	$6.20	$6.50	$6.68	$6.50	$7.09	$7.34	$7.88	$7.23	$9.51	$7.84	$8.15	$9.03	$8.55
		$7.05	$7.47	$8.07	$9.47	$10.44	$10.88	$11.28	$10.08	$10.25	$12.22	$11.04	$11.61	$12.73	$12.76

	Fig.	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Affordability															
Residential rates (as of July 1)	36														
Bill (698kWh)		$79	$84	$89	$90	$91	$105	$103	$97	$99	$110	$113	$113	$112	$126
Bill (1000kWh)		$110	$115	$119	$128	$125	$144	$142	$132	$137	$152	$157	$157	$156	$179
Components ($/kWh, May 1 of *following* year, as of July 1 for 2021)															
base fuel								$0.0325	$0.0325	$0.0325	$0.0267	$0.0267	$0.0267	$0.0267	N/A
O&M expense								$0.0294	$0.0294	$0.0294	$0.0406	$0.0406	$0.0406	$0.0406	N/A
D&A expense								$0.0133	$0.0133	$0.0133	$0.0259	$0.0259	$0.0259	$0.0259	N/A
taxes								$0.0100	$0.0073	$0.0073	$0.0072	$0.0072	$0.0072	$0.0072	N/A
NOI and settlement adjust't								$0.0130	$0.0130	$0.0130	$0.0220	$0.0220	$0.0220	$0.0220	N/A
capital trackers								$0.0016	$0.0038	$0.0039	$0.0028	$0.0013	$0.0032	$0.0014	N/A
expense trackers								$0.0138	$0.0126	$0.0077	$0.0121	$0.0184	$0.0170	-$0.0001	N/A
total								$0.1136	$0.1119	$0.1071	$0.1373	$0.1421	$0.1426	$0.1236	N/A
Variable charges (cents) (as of July 1 for 2023)															
811 energy							11.0433	11.0433	10.6764	10.6764	0.1241	0.124141	0.124141	0.122108	N/A
870 FAC							0.2625	0.0836	-0.3279	-0.1999	-0.0011	0.0031	0.0098	0.0045	N/A
871 RTO							0.1664	0.1220	0.2138	0.1015	0.0026	0.003767	0.002835	0.002357	N/A
872 ECR							0.9330	0.4221	0.2963	0.2745	0	0	0	0	N/A
874 RA							0.3030	0.4388	0.4160	0.3651	0.0041	-0.00031	0.000136	0.000644	N/A
883 DSM							0.3157	0.3770	0.2272	0.5053	0.0056	0.006331	0.0052951	0.003612	N/A
887 FMC							-0.0011	-0.0019	0.0249	0.1325	0.0003	0.0000	0.0000	0.0000	N/A
888 TDSIC							0.0000	0.3204	0.3159	0.3813	0.0011	0.003722	0.002997	0.007746	N/A
Total variable charge							13.0228	12.8053	11.8426	12.2367	0.1368	0.1368	0.1368	0.1409	N/A
Customer charge ($)						$11.00	$14.00	$14.00	$14.00	$14.00	$13.50	$13.50	$13.50	$13.50	N/A
Commercial rates															
Rate 721 3 kW .375 MWh 17%		$0.181	$0.180	$0.183	$0.198	$0.186	$0.218	$0.217	$0.212	$0.210	$0.236	$0.242	$0.245	$0.242	$0.269
Rate 721 12 kW 1.5 MWh 17%		$0.141	$0.140	$0.143	$0.158	$0.146	$0.170	$0.169	$0.164	$0.162	$0.175	$0.182	$0.185	$0.181	$0.203
Rate 723 40 kW 10 MWh 34%		$0.130	$0.123	$0.131	$0.142	$0.132	$0.153	$0.152	$0.148	$0.147	$0.158	$0.164	$0.167	$0.164	$0.184
Rate 723 40 kW 14 MWh 48%		$0.115	$0.108	$0.116	$0.127	$0.117	$0.137	$0.136	$0.131	$0.131	$0.144	$0.151	$0.153	$0.148	$0.173
Rate 723 500 kW 150 MWh 41%		$0.104	$0.104	$0.108	$0.115	$0.107	$0.124	$0.124	$0.120	$0.119	$0.130	$0.135	$0.141	$0.136	$0.167
Rate 724 500 kW 180 MWh 49%		$0.097	$0.097	$0.101	$0.108	$0.100	$0.117	$0.116	$0.113	$0.111	$0.122	$0.127	$0.133	$0.128	$0.156
Industrial rates															
Rate 723 75 kW 15 MWh 27%	38	$0.136	$0.129	$0.137	$0.147	$0.137	$0.159	$0.159	$0.154	$0.154	$0.168	$0.175	$0.177	$0.172	$0.205
Rate 723 75 kW 30 MWh 55%		$0.107	$0.100	$0.108	$0.118	$0.108	$0.128	$0.127	$0.123	$0.122	$0.135	$0.141	$0.144	$0.139	$0.160
Rate 724 75 kW 50 MWh 91%	38	$0.093	$0.088	$0.096	$0.104	$0.096	$0.111	$0.111	$0.107	$0.106	$0.116	$0.122	$0.127	$0.123	$0.143
Rate 724 1,000 kW 200 MWh 27%		$0.120	$0.120	$0.125	$0.132	$0.124	$0.142	$0.142	$0.138	$0.137	$0.149	$0.154	$0.159	$0.155	$0.193
Rate 724 1,000 kW 400 MWh 55%		$0.091	$0.091	$0.095	$0.102	$0.094	$0.111	$0.110	$0.107	$0.105	$0.116	$0.121	$0.126	$0.122	$0.148
Rate 724 1,000 kW 650 MWh 89%		$0.080	$0.080	$0.084	$0.091	$0.083	$0.099	$0.098	$0.095	$0.093	$0.103	$0.108	$0.114	$0.110	$0.130
Rate 732 50,000 kW 15,000 MWh 69%	38	$0.075	$0.076	$0.080	$0.084	$0.078	$0.088	$0.097	$0.093	$0.079	$0.076	$0.088	$0.091	$0.091	$0.126
Rate 73350,000 kW 25,000 MWh 83%	38	$0.068	$0.067	$0.071	$0.075	$0.069	$0.079	$0.079	$0.076	$0.070	$0.075	$0.082	$0.088	$0.075	$0.092
Rate 733 50,000 kW 32,500 MWh 100%		$0.057	$0.065	$0.066	$0.071	$0.065	$0.072	$0.071	$0.068	$0.066	$0.067	$0.077	$0.083	$0.070	$0.085
Residential disconnections															
Non-Payment	40	20,088	19,585	17,271	15,824	15,011	12,689	11,900	8,232	7,854	4,537	7,361	7,314	7,319	3,576
Notices Sent (000)	40	454	454	460	480	455	438	446	458	448	244	363	415	416	421
Disconnections by Month															
Jan		1,408	1,875	1,466	354	863	835	1,304	22	483	837	454	273	575	142
Feb		866	1,560	1,284	219	323	912	1,456	415	881	600	293	282	700	196
Mar		2,018	1,806	1,418	1,084	1,411	1,068	1,132	928	776	468	664	713	829	365
Apr		1,751	1,655	1,892	1,653	1,635	953	817	861	786	0	780	731	705	592
May		1,748	1,571	1,580	1,665	1,318	740	1,150	1,253	628	0	645	862	783	543
Jun		1,711	1,339	1,145	1,635	1,393	872	962	997	726	1	642	746	720	308
Jul		1,482	1,029	1,323	1,353	907	885	854	801	628	0	537	748	423	123
Aug		1,914	1,644	1,196	1,437	1,262	1,185	1,323	808	684	12	629	586	574	164
Sep		1,607	1,471	1,061	1,425	908	951	745	406	691	879	839	676	521	299
Oct		1,436	1,553	1,365	1,341	1,158	939	1,026	619	677	668	620	650	523	331
Nov		1,211	1,107	796	452	999	930	804	533	456	611	585	575	477	347
Dec		925	963	732	1,192	819	403	327	589	438	461	673	472	489	166
Accounts in Arrears															
Jan		4.0%	3.0%	2.7%	2.8%	2.8%	2.9%	2.6%	3.5%	2.8%	2.5%	4.8%	3.8%	3.9%	4.4%
Feb		4.2%	2.8%		2.8%	2.9%	2.4%	2.4%	3.5%	2.8%	2.6%	4.5%	4.1%	3.8%	4.0%
Mar		4.1%	2.6%	2.4%	2.5%	2.5%	2.0%	2.2%	3.2%	2.5%	2.7%	3.8%	3.5%	3.6%	4.0%
Apr		3.6%	2.5%	2.1%	2.5%	2.3%	2.3%	2.5%	2.7%	2.6%	4.1%	3.0%	3.8%	4.3%	4.1%
May		3.7%	2.7%	2.2%	2.7%	2.6%	2.3%	2.4%	2.3%	2.7%	5.7%	2.9%	3.9%	4.4%	3.8%
Jun		3.0%	2.8%	2.7%	2.8%	2.4%	2.2%	2.4%	2.5%	3.1%	6.0%	2.8%	3.5%	4.3%	4.2%
Jul		3.1%	2.3%	2.4%	2.6%	2.4%	2.4%	2.6%	2.4%	3.0%	6.5%	2.6%	3.6%	4.4%	4.1%
Aug		2.7%	2.1%	2.3%	2.4%	2.1%	2.0%	2.0%	2.3%	2.3%	5.8%	2.5%	3.3%	4.0%	4.0%
Sep		2.0%	2.2%	2.3%	2.2%	2.1%	1.9%	2.5%	2.5%	2.5%	5.6%	2.4%	3.2%	3.9%	4.1%
Oct		2.5%	2.6%	2.5%	2.3%	2.3%	2.4%	2.6%	2.6%	3.0%	5.4%	2.6%	3.4%	4.0%	4.4%
Nov		3.0%	2.7%	3.0%	3.1%	2.5%	2.7%	2.8%	2.8%	3.5%	4.9%	2.8%	3.3%	4.3%	4.9%
Dec		3.3%	3.1%	3.6%	3.3%	2.9%	3.2%	3.6%	3.2%	3.6%	5.1%	3.1%	4.0%	4.8%	5.4%
Average	41	3.3%	2.6%	2.6%	2.7%	2.5%	2.4%	2.5%	2.8%	2.9%	4.7%	3.2%	3.6%	4.1%	4.3%
Staffing															
Employee turnover	42	6.7%	5.1%	6.8%	5.6%	6.2%	5.9%	6.3%	7.3%	6.7%	5.8%	8.2%	6.3%	5.8%	6.1%
% Female	43					23.37%	23.59%	23.08%	23.55%	23.88%	24.01%	23.50%	23.78%	24.52%	24.63%
% Non-White	43					15.28%	15.86%	16.21%	16.90%	17.06%	17.63%	18.01%	18.52%	19.21%	20.61%
Ratio data															
Energy (MWh, millions)															
		15.39	13.28	14.18	14.79	12.20	12.11	12.02	12.04	10.32	7.61	8.10	6.99	5.98	$7
		16.84	16.76	16.80	17.51	16.56	16.81	16.69	16.33	15.71	14.62	15.61	15.17	14.78	$15
		0.65	0.25	0.67	0.68	0.19	0.02	0.03	0.11	0.010	0.08	0.12	0.05	0	$0
O&M ($, millions)															
		$952	$958	$1,003	$1,097	$990	$1,046	$1,095	$996	$972	$809	$910	$1,072	$957	$866
		$162	$182	$168	$179	$185	$214	$237	$182	$169	$153	$144	$119	$114	$75
		$547	$497	$545	$614	$491	$498	$517	$506	$471	$319	$442	$611	$473	$401
		$0	$10	$6	$5	$5	$5	$6	$6	$6	$5	$6	$5	$5	$6
		$20	$22	$29	$31	$36	$44	$46	$45	$50	$49	$53	$55	$54	$60
		$44	$48	$48	$44	$41	$44	$50	$55	$58	$63	$63	$65	$65	$74
		$19	$21	$23	$22	$20	$19	$18	$18	$19	$16	$17	$19	$18	$19
		$161	$178	$183	$203	$212	$221	$221	$185	$200	$204	$185	$196	$228	$231

MED - See MED Appendix Data
EDG - See EDG Table

MED Appendix Data

Date	SAIDI	SAIFI	Date	SAIDI	SAIFI	Date	SAIDI	SAIFI	Date	SAIDI	SAIFI	Date	SAIDI	SAIFI	Date	SAIDI	SAIFI	Date	SAIDI	SAIFI	Date	SAIDI	SAIFI
5/29/2011	17.72	0.0434	6/29/20112	53.75	0.078	3/12/2014	30.9	0.1174	2/19/2016	9.83	0.0499	2/12/2019	17.59	0.0553	6/9/2020	12.371	0.0428	4/14/2022	11.022	0.0459	2/22/2023	24.354	0.0269
5/30/2011	2.83	0.0115	6/30/2012	7.13	0.0191	3/13/2014	0.09	0.0007	2/20/2016	0.28	0.0017	2/13/2019	0.18	0.0014	6/10/2020	31.083	0.0483	4/15/2022	1.594	0.0115	2/23/2023	1.822	0.0040
5/31/2011	0.27	0.035	7/1/2012	7.34	0.0279	5/11/2014	31.01	0.0628	2/21/2016	0.02	0.0002	5/23/2019	41.01	0.0891	6/11/2020	0.947	0.0022	6/13/2022	54.342	0.0648	2/24/2023	0.089	0.0003
6/4/2011	98.8	0.0976	7/2/2012	0.3	0.0034	5/12/2014	6.78	0.0114	2/24/2016	56.4	0.105	5/24/2019	0.78	0.0048	6/12/2020	0.365	0.0029	6/14/2022	12.326	0.0212	3/3/2023	13.850	0.0402
6/5/2011	19.47	0.0137	7/5/2012	22.23	0.0548	5/13/2014	0.73	0.0039	2/25/2016	3.65	0.0104	5/25/2019	0.1	0.0005	6/26/2020	17.243	0.0418	6/15/2022	0.862	0.0035	3/4/2023	1.071	0.0024
6/6/2011	4.46	0.0097	7/6/2012	1.9	0.0057	5/14/2014	0.1	0.001	2/26/2016	0.15	0.0011	6/26/2019	7.88	0.0297	6/27/2020	1.442	0.0049	6/16/2022	0.928	0.0078	3/5/2023	0.055	0.0008
6/7/2011	1.15	0.005	7/7/2012	0.29	0.0048	6/30/2014	202.78	0.2132	7/21/2016	9.25	0.0448	6/27/2019	3.42	0.0167	6/28/2020	0.311	0.0017	7/5/2022	10.28	0.047	3/31/2023	37.406	0.0500
6/8/2011	0.62	0.0052	7/18/2012	20.08	0.0535	7/1/2014	168.11	0.1271	7/22/2016	0.68	0.0031	6/28/2019	0.29	0.0027	8/10/2020	242.893	0.2105	7/6/2022	1.66	0.0068	4/1/2023	3.805	0.0081
6/9/2011	2.4	0.0167	7/19/2012	6.39	0.0281	7/2/2014	9.63	0.0098	12/4/2016	15.37	0.0479	8/18/2019	25.03	0.0594	8/11/2020	31.157	0.0194	7/23/2022	45.264	0.097	4/2/2023	1.820	0.0081
7/1/2011	13.55	0.0446	7/20/2012	0.1	0.0007	7/3/2014	3.69	0.0121	12/5/2016	1.11	0.0093	8/19/2019	0.5	0.0026	8/12/2020	5.813	0.0045	7/24/2022	1.592	0.0067	4/3/2023	0.130	0.0008
7/2/2011	2.83	0.0134	7/24/2012	100.66	0.167	7/4/2014	0.87	0.005	1/10/2017	13.44	0.0584	8/20/2019	0.22	0.0013	8/13/2020	1.175	0.0013	7/25/2022	0.415	0.003	4/4/2023	2.488	0.0191
7/3/2011	0.16	0.0011	7/25/2012	3.13	0.0074	7/5/2014	0.15	0.0006	1/11/2017	0.81	0.0042	9/3/2019	9.07	0.036	8/14/2020	1.343	0.006	8/3/2022	26.364	0.0565	4/5/2023	1.789	0.0130
7/11/2011	17.71	0.0537	7/26/2012	1.49	0.0064	9/20/2014	11.17	0.0318	3/8/2017	8.78	0.0452	9/4/2019	0.06	0.0005	8/15/2020	0.611	0.0028	8/4/2022	1.766	0.0088	7/5/2023	10.597	0.0291
7/12/2011	0.42	0.0034	8/4/2012	93.59	0.14	9/21/2014	1.84	0.0089	3/9/2017	0.05	0.0003	9/27/2019	25.46	0.0676	1/1/2021	130.273	0.1198	8/5/2022	0.204	0.0012	7/6/2023	1.049	0.0056
7/13/2011	0.42	0.007	8/5/2012	6.67	0.0135	9/22/2014	0.21	0.001	7/4/2018	16.1	0.042	9/28/2019	1.3	0.0037	1/2/2021	20.26	0.0156	8/29/2022	32.676	0.0758	7/7/2023	0.107	0.0007
7/22/2011	24.27	0.0545	8/6/2012	0.25	0.0018	10/31/2014	40.66	0.0742	7/5/2018	8.37	0.0278	9/29/2019	0.74	0.004	1/3/2021	11.454	0.0193	8/30/2022	2.223	0.0075	7/28/2023	59.445	0.0825
7/23/2011	4.56	0.0129	8/7/2012	0.13	0.0007	11/1/2014	0.72	0.0017	7/6/2018	0.39	0.0019	10/21/2019	66.08	0.1229	1/4/2021	0.503	0.0025	8/31/2022	0.227	0.0017	7/29/2023	26.657	0.0403
7/24/2011	1.78	0.0091	6/12/2013	40.36	0.0965	11/2/2014	0.14	0.0009	7/7/2018	0.08	0.0007	10/22/2019	3.18	0.0063	1/5/2021	0.074	0.0005	10/17/2022	17.164	0.0279	7/30/2023	0.868	0.0026
7/25/2011	0.27	0.0033	6/13/2013	5.55	0.0126	2/1/2015	15.65	0.0543	7/8/2018	0.45	0.0024	10/23/2019	0.38	0.0036	6/20/2021	24.499	0.0369	10/18/2022	1.168	0.0049	7/31/2023	0.161	0.0007
#########	24.1	0.0438	6/14/2013	0.18	0.0011	2/2/2015	0.24	0.0012	9/25/2018	14.2	0.0447	10/24/2019	0.19	0.0012	6/21/2021	58.089	0.104	10/19/2022	0.976	0.005	7/15/2024	293.924	0.2447
#########	7.41	0.0104	6/24/2013	176.66	0.216	7/18/2015	18.4	0.0046	9/26/2018	1.19	0.0065	11/27/2019	12.52	0.053	6/22/2021	0.486	0.004	11/5/2022	17.284	0.05	7/16/2024	34.406	0.0381
12/1/2011	0.12	0.0006	6/25/2013	38.61	0.0457	7/19/2015	0.74	0.0027	10/20/2018	12.76	0.0377	11/28/2019	0.21	0.0021	6/23/2021	0.188	0.0012	11/6/2022	0.57	0.0027	7/17/2024	10.232	0.0105
			6/26/2013	12.42	0.0119	12/28/2015	85.89	0.1257	10/21/2018	0.13	0.0009				6/26/2021	11.217	0.0255	11/7/2022	0.239	0.0021	7/18/2024	0.562	0.0014
			6/27/2013	51.3	0.0736	12/29/2015	3.88	0.0061	11/26/2018	41.65	0.0892				6/27/2021	0.811	0.0027	11/8/2022	0.107	0.0012	7/19/2024	0.272	0.0010
			6/28/2013	7.75	0.0257	12/30/2015	0.97	0.0049	11/27/2018	0.13	0.0004				6/28/2021	2.462	0.0141				7/20/2024	0.085	0.0006
			6/29/2013	0.99	0.0061	12/31/2015	0.05	0.0002	11/28/2018	0.06	0.0006				8/11/2021	48.251	0.0601				8/27/2024	13.262	0.0246
			11/17/2013	88.4	0.1684										8/12/2021	26.482	0.041				8/28/2024	2.093	0.0098
			11/18/2013	5.06	0.0086										8/13/2021	0.608	0.002				8/29/2024	0.048	0.0004
			11/19/2013	0.87	0.0054										8/14/2021	0.282	0.0022				12/4/2024	13.831	0.0545
			11/20/2013	0.16	0.0012										8/25/2021	9.542	0.0269				12/5/2024	0.543	0.0073
			11/21/2013	0.29	0.0024										8/26/2021	1.13	0.0055						
															12/11/2021	14.742	0.0447						
															12/12/2021	0.101	0.0008						
															12/13/2021	0.084	0.0006						

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

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

Exhibit 14
Saffran Q1 2025 Outage Testimony

VERIFIED DIRECT TESTIMONY OF DAVID SAFFRAN

Q1. Please state your name, title, and business address.

A1. My name is David Saffran. My title is Generation Business Systems Administrator in the Operations Management Reporting division of Northern Indiana Public Service Company LLC ("NIPSCO" or the "Company"). My business address is 2755 Raystone Drive, Valparaiso, Indiana 46383.

Q2. Please describe your educational and employment background.

A2. I hold an Associate degree in Electronic Systems Technology from the Community College of the Air Force, an Associate degree in Aerospace Ground Equipment Technology from the Community College of the Air Force and have attended classes for three years working towards a Bachelor of Science degree in Computer Networking Information Technology at Purdue Northwest. I have been employed by NiSource Inc. or NIPSCO since May of 2004 in a variety of technical, supervisory, and administrative positions.

Q3. What are your responsibilities as Generation Business Systems

Administrator in the Operations Management Reporting division of NIPSCO?

A3. My current responsibilities include managing NIPSCO's various business systems and programs, recording data concerning Generation's operational and maintenance performance, and analyzing the results to identify adverse trends and recommend corrective actions to improve performance. In addition, I am responsible for submitting various NIPSCO Generation reports and filings to local, state, and federal agencies such as the Indiana Utility Regulatory Commission ("Commission"), Midcontinent Independent System Operator, Inc., North American Electric Reliability Council, Federal Energy Regulatory Commission ("FERC") and Indiana Department of Natural Resources ("DNR").

Q4. Are you familiar with the Company's Verified Petition, including the exhibits attached thereto, initiating this proceeding, a copy of which has been marked <u>Attachment 1-A</u>?

A4. Yes.

Q5. What is the purpose of your direct testimony in this proceeding?

A5. The purpose of my testimony is to provide information relevant to Paragraph 6 of Exhibit A - Settlement Terms, attached to the Stipulation and Agreement filed October 16, 2007 in Cause No. 38706-FAC71-S1 approved by the Commission on January 30, 2008 ("FAC71-S1 Agreement") and Paragraph 6(f.) of the Stipulation and Agreement filed September 23, 2009 in Cause No. 38706-FAC80-S1 approved by the Commission on November 4, 2009 ("FAC80-S1 Agreement") (collectively, the "Reporting Agreements"). Paragraph 6 of the FAC71-S1 Agreement calls for NIPSCO to submit testimony in its quarterly FAC proceedings regarding major forced outages that occur within the pertinent FAC timeframe. Under this provision, NIPSCO must describe the length and cause of each major forced outage, generating unit involved, and proposed solutions to prevent such outages from occurring in the future. In addition to the above provision regarding the details of each major forced outage, Paragraph 6(f.) of the FAC80-S1 Agreement calls for NIPSCO to file testimony describing the details of and the steps taken to minimize such major forced outages in the future. Paragraph 6(f.) of the FAC80-S1 Agreement defines a "major forced outage" as a unit forced outage lasting longer than three (3) consecutive days.

Q6. Are you sponsoring any attachments to your testimony?

A6. Yes. I am sponsoring Attachment 4-A and Confidential Attachment 4-B, both of which were prepared by me or under my direction and supervision. Attachment 4-A describes each major forced outage NIPSCO's generating units experienced during the first quarter of 2025, which is the reconciliation period in this FAC proceeding. Confidential Attachment 4-B contains root-cause analysis reports regarding the outages listed in Attachment 4-A that were complete at the time of this filing.

Q7. Does Attachment 4-A comply with the Reporting Agreements?

A7. Yes. In the Attachment, I explain each major forced outage and state the actions NIPSCO has already taken or is able to take to prevent each outage from occurring again.

Q8. Does Confidential Attachment 4-B comply with the Commission's October 29, 2019 Order in Cause No. 38706-FAC-124 ("FAC-124 Order")?

A8. Yes. In its FAC-124 Order, the Commission directed NIPSCO to provide in its future quarterly FAC filings, a root cause analysis for forced outages when such an analysis has been completed at the time of the FAC filing. That information is provided in Confidential Attachment 4-B.

Q9. Does this conclude your prepared direct testimony?

A9. Yes.

VERIFICATION

I, David Saffran, Generation Business Systems Administrator in the Operations Management Reporting division of Northern Indiana Public Service Company LLC, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

David Saffran

Dated: May 23, 2025

Major Forced Outage Report (Q1, 2025)

Michigan City 12	The unit was taken out of service due to a condenser tube leak.
January 22	Maintenance found the ventilator valve was bleeding through and steam cut the tubes.
112 hours	The cut tubes were plugged, and the valve repaired.
R. M. Schahfer 16A	The unit was taken out of service due to high blade path temperature spread during startup.
January 17	The fuel nozzles were found to be cracked and needed to be replaced.
704 hours	New fuel nozzles were procured and replaced.
R. M. Schahfer 17	Boiler tube leak in superheat platen.
January 15	The initial cause was an improperly bent tube that created a restriction and caused overheating. This resulted in a chain reaction that damaged the surrounding tubes.
272 hours	The sections of failed and damaged tubes were replaced.
R. M. Schahfer 18	Boiler tube leak on the southwest water wall.
January 29	The leak appears to be due to falling slag.
150 hours	Replaced tubes and pad welded where needed.
R. M. Schahfer 18	The unit tripped due to high turbine bearing vibration indications on all rotor bearings. **Boiler tube leak on southwest wall.**
February 16	The contractor found L-1 turbine blade had liberated from its root and fell into the condenser.
1,052 hours	The rotor was removed and sent out for repair.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

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

Exhibit 15
Saffran Q2 2025 Outage Testimony

VERIFIED DIRECT TESTIMONY OF DAVID SAFFRAN

Q1. Please state your name, title, and business address.

A1. My name is David Saffran. My title is Generation Business Systems Administrator in the Operations Management Reporting division of Northern Indiana Public Service Company LLC ("NIPSCO" or the "Company"). My business address is 2755 Raystone Drive, Valparaiso, Indiana 46383.

Q2. Please describe your educational and employment background.

A2. I hold an Associate degree in Electronic Systems Technology from the Community College of the Air Force, an Associate degree in Aerospace Ground Equipment Technology from the Community College of the Air Force and have attended classes for three years working towards a Bachelor of Science degree in Computer Networking Information Technology at Purdue Northwest. I have been employed by NiSource Inc. or NIPSCO since May of 2004 in a variety of technical, supervisory, and administrative positions.

Q3. What are your responsibilities as Generation Business Systems

Administrator in the Operations Management Reporting division of NIPSCO?

A3. My current responsibilities include managing NIPSCO's various business systems and programs, recording data concerning Generation's operational and maintenance performance, and analyzing the results to identify adverse trends and recommend corrective actions to improve performance. In addition, I am responsible for submitting various NIPSCO Generation reports and filings to local, state, and federal agencies such as the Indiana Utility Regulatory Commission ("Commission"), Midcontinent Independent System Operator, Inc., North American Electric Reliability Council, Federal Energy Regulatory Commission ("FERC") and Indiana Department of Natural Resources ("DNR").

Q4. Are you familiar with the Company's Verified Petition, including the exhibits attached thereto, initiating this proceeding, a copy of which has been marked <u>Attachment 1-A</u>?

A4. Yes.

Q5. What is the purpose of your direct testimony in this proceeding?

A5. The purpose of my testimony is to provide information relevant to Paragraph 6 of Exhibit A - Settlement Terms, attached to the Stipulation and Agreement filed October 16, 2007 in Cause No. 38706-FAC71-S1 approved by the Commission on January 30, 2008 ("FAC71-S1 Agreement") and Paragraph 6(f.) of the Stipulation and Agreement filed September 23, 2009 in Cause No. 38706-FAC80-S1 approved by the Commission on November 4, 2009 ("FAC80-S1 Agreement") (collectively, the "Reporting Agreements"). Paragraph 6 of the FAC71-S1 Agreement calls for NIPSCO to submit testimony in its quarterly FAC proceedings regarding major forced outages that occur within the pertinent FAC timeframe. Under this provision, NIPSCO must describe the length and cause of each major forced outage, generating unit involved, and proposed solutions to prevent such outages from occurring in the future. In addition to the above provision regarding the details of each major forced outage, Paragraph 6(f.) of the FAC80-S1 Agreement calls for NIPSCO to file testimony describing the details of and the steps taken to minimize such major forced outages in the future. Paragraph 6(f.) of the FAC80-S1 Agreement defines a "major forced outage" as a unit forced outage lasting longer than three (3) consecutive days.

Q6. Are you sponsoring any attachments to your testimony?

A6. Yes. I am sponsoring Attachment 4-A and Confidential Attachment 4-B, both of which were prepared by me or under my direction and supervision. Attachment 4-A describes each major forced outage NIPSCO's generating units experienced during the second quarter of 2025, which is the reconciliation period in this FAC proceeding. Confidential Attachment 4-B contains root-cause analysis reports regarding the outages listed in Attachment 4-A that were complete at the time of this filing.

Q7. Does Attachment 4-A comply with the Reporting Agreements?

A7. Yes. In the Attachment, I explain each major forced outage and state the actions NIPSCO has already taken or is able to take to prevent each outage from occurring again.

Q8. Does Confidential Attachment 4-B comply with the Commission's October 29, 2019 Order in Cause No. 38706-FAC-124 ("FAC-124 Order")?

A8. Yes. In its FAC-124 Order, the Commission directed NIPSCO to provide in its future quarterly FAC filings, a root cause analysis for forced outages when such an analysis has been completed at the time of the FAC filing. That information is provided in Confidential Attachment 4-B.

Q9. Does this conclude your prepared direct testimony?

A9. Yes.

VERIFICATION

I, David Saffran, Generation Business Systems Administrator in the Operations Management Reporting division of Northern Indiana Public Service Company LLC, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

David Saffran

Dated: August 18, 2025

Major Forced Outage Report (Q2, 2025)

R. M. Schahfer 16A June 11 *153 hours*	Main lube oil pump motor failed. Electric maintenance found the motor windings were grounded. A new motor was purchased to replace the failed motor. The unit was returned to service June 17.
R. M. Schahfer 16B June 16 *75 hours*	Turbine lube oil leak around #5 exhaust bearing. The investigation found the leak originated from a seal-tight connection for a temperature probe. The oil ran from the probe down the wire harness before dripping onto the ground, making its origin difficult to identify. The connection was tightened and epoxy applied around the connector to prevent future leaks.
R. M. Schahfer 18 February 16 *2,980 hours*	The unit tripped due to high turbine bearing vibration indications on all rotor bearings. This event was reported in FAC 147. **Boiler tube leak on southwest wall.** The contractor found L-1 turbine blade had liberated from its root and fell into the condenser. The rotor was removed and sent out for repair. Unit placed in reserve status on 6/20 and placed online on 6/23.
Norway Hydro June 6 *93 hours*	Unit 4 governor failed—no other units available. The proportional valve failed, and no other units were available; Unit 3 was waiting for brake ring repairs, Unit 2 was off for an oil leak, and Unit 1 was off for bound wicket gates. The valve was replaced and the unit placed back in service at minimum load.

Confidential Attachment 4-B (Redacted)