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 151
August Campbell Order

Order No. 202-25-7

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

Order No. 202-25-3

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

Order No. 202-25-3, issued pursuant to FPA section 202(c), required that the Campbell Plant remain in operation for 90 days, until August 21, 2025. That order was based on my determination that emergency conditions existed in the region served by the Midcontinent Independent System Operator, Inc. (MISO). Specifically, I determined that MISO likely faced tight reserve margins during the summer 2025 period, particularly during periods of high demand or low generation resource output. I determined that the continued operation of the Campbell Plant would provide additional generation capacity during these periods which would help prevent the potential loss of power to homes and local businesses in the areas that might have been affected by curtailments or outages that would otherwise pose a risk to public health and safety. I determined that the continued operation of the Campbell Plant was necessary to alleviate immediate and anticipated threats to reliability. My determination was based on a number of facts.

First, the North American Electric Reliability Corporation (NERC) released its 2025 Summer Reliability Assessment on May 14, 2025. In its assessment, NERC indicated that "[d]emand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output."[2] In particular, NERC explained that the retirement of thermal generation capacity increased the likelihood of electricity supply

[1] *See Consumers Energy Announces Plan to End Coal Use by 2025; Lead Michigan's Clean Energy Transformation*, Consumers Energy (June 23, 2021), https://www.consumersenergy.com/news-releases/news-release-details/2021/06/23/consumers-energy-announces-plan-to-end-coal-use-by-2025-lead-michigans-clean-energy-transformation. As a coal-fired facility, it would be difficult for the Campbell Plant to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30-60 days to repair if a unit comes offline.

[2] *2025 Summer Reliability Assessment*, North American Electric Reliability Corporation, at 16 (May 2025), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf (NERC 2025 Summer Reliability Assessment).

shortfalls. NERC anticipated that the near-term period of greatest capacity shortfall for MISO would likely occur in August.[3]

Second, multiple generation facilities in Michigan have retired in recent years. According to the U.S. Energy Information Administration (EIA), "[s]ince 2020, about 2,700 megawatts of coal-fired generating capacity have been retired and no new coal-fired facilities are planned."[4] Additionally, EIA stated, "[t]ypically, Michigan's nuclear power plants have supplied about 30% of in-state electricity, but the amount of electricity generated by nuclear power plants in Michigan has declined as plants have been decommissioned."[5] The state's Big Rock Point nuclear power plant shut down in 1997, and the Palisades nuclear power plant closed in 2022. While the Palisades nuclear power plant may reopen in 2025, it was not projected to be available during the peak demand period this summer.[6]

Third, the Campbell Plant's retirement would have further decreased available dispatchable generation within MISO's service territory, adding to the loss of the other 1,575 MW of natural gas and coal-fired generation that has retired since the summer of 2024. Although MISO and Consumers have incorporated the planned retirement of the Campbell Plant into their supply forecasts and Consumers acquired a 1,200 MW natural gas power plant in Covert, MI, the NERC Assessment still anticipates "elevated risk of operating reserve shortfalls."[7]

Fourth, MISO's Planning Resource Auction Results for the 2025-2026 Planning Year, released in April 2025, noted that for the northern and central zones, which includes Michigan, "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources."[8] While the results "demonstrated sufficient capacity," the summer months reflected the "highest risk and a tighter supply-demand balance" and these results "reinforce the need to increase capacity."[9]

Continuing Emergency Conditions

The emergency conditions that led to the issuance of Order No. 202-25-3 continue, both in the near and long term. The summer season has not yet ended, and the production of electricity from the Campbell Plant will continue to be a critical asset to maintain reliability in MISO this summer. That need is evidenced by the fact that the Campbell Plant was called on by MISO to generate large amounts of electricity during the heat wave that hit MISO this past June. According

---

[3] *Id.*
[4] *Michigan State Profile and Energy Estimates*, U.S. Energy Info. Admin. (Oct. 17, 2024), https://www.eia.gov/state/print.php?sid=MI.
[5] *Id.*
[6] The start-up of Palisades is scheduled for the fourth quarter of 2025.
[7] NERC 2025 Summer Reliability Assessment at 16.
[8] *Planning Resource Auction—Results for Planning Year 2025–2026,* Midcontinent Independent System Operator, Inc., 13 (May 29, 2025), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf. (MISO Planning Resource Auction – Results for Planning Year 2025-26).
[9] *Id*. at 2,12.

to the U.S. Environmental Protection Agency's data, over the month of June, the Campbell Plant generated approximately 664,000 MWh, running at 61% capacity.[10] In fact, between June 11 and August 18, MISO issued dozens of alerts to manage grid reliability in its Central Region in response to hot weather, severe weather, high customer load, forced generation outages, and transfer capability limits. MISO issued alerts for the Central Region on at least 40 of the 69 days between June 11 and August 18. In June, MISO issued alerts affecting the Central Region on 18 days, including an Energy Emergency Alert (EEA) level 1 ("Max Gen Step 1b") on June 23 to enable MISO to take emergency action to ensure grid stability, including bringing additional resources online.[11] The Central Region had alerts on 21 days in July, including one Max Generation Warning on July 29 and two Max Generation Alerts on July 28 and 29.[12] Two Capacity Advisory Initiate alerts have been issued in August to date.[13] Moreover, the May 2025 NERC Summer Reliability Assessment referenced a Seasonal Outlook issued by the National Oceanic and Atmospheric Administration (NOAA), which estimates that much of the Midwest has a 33%-40% chance to experience above-normal temperatures this summer.[14] The Seasonal Outlook released by NOAA on July 17, 2025, increased this estimate for much of the region to a 40%-50% chance.[15]

MISO's resource adequacy problems are not limited to the summer. 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.[16] MISO justified this revision by explaining that "Reliability risks associated with resource adequacy have shifted from 'Summer only' to a year-round

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

[11] An Energy Emergency Alert is an alert declared by the Transmission Provider in accordance with the NERC Operating Manual associated with the Transmission Provider's inability to provide for the Energy and Operating Reserve requirements of the MISO Balancing Authority Area. For more information, see MISO, FERC Electric Tariff, Module A, § 1.E (Definitions) (92.0.0). For more information on Energy Emergency Alert levels, see North American Electric Reliability Corporation. (n.d.). *EOP-011-1 Emergency Operations*. https://www.nerc.com/pa/stand/reliability%20standards/eop-011-1.pdf.

[12] A Max Gen Alert occurs when MISO is forecasting a potential capacity shortage. A Max Gen Warning is a warning to prepare for a possible Max Gen Event. *See* MISO Operating Procedures, https://efis.psc.mo.gov/Document/Display/9379 (20180920).

[13] A Capacity Advisory alert is an advisory issued based on the potential for limited operating capacity margins (<5%) in the following 2-3 days. *See* MISO Operating Procedures, https://efis.psc.mo.gov/Document/Display/9379 (20180920).

[14] NERC 2025 Summer Assessment at 9.

[15] *Seasonal Outlook*, NOAA Climate Prediction Ctr., (July 17, 2025), https://www.cpc.ncep.noaa.gov/products/predictions/long_range/seasonal.php?lead=1.

[16] M*idcontinent Independent System Operator, Inc.,* FERC Docket No. ER22-495-000 (Nov. 30, 2021). This request was approved by FERC on August 31, 2022. Midcontinent Independent System Operator, Inc., 180 FERC ¶ 61,141 (2022).

concern."[17] MISO noted that over 60 percent 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.[18]

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."[19] 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 projects 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.[20]

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.*"[21] 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.[22]

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. 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 Michigan.[23]

On June 6, 2025, subsequent to the issuance of Order No. 202-25-3, 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

---

[17] MISO Transmittal Letter at 3, FERC Docket No. ER22-495-000 (Nov. 30, 2021).
[18] *Id.* at 3-4.
[19] *Attributes Roadmap*, MISO (Dec. 2023), https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf.
[20] *Id.* at 11.
[21] *MISO's Response to the Reliability Imperative*, MISO (Updated Feb. 2024), https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf.
[22] *Id.* at 12.
[23] MISO Planning Resource Auction – Results for Planning Year 2025-26 at 13.

planning reserve margin requirements.[24] 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.[25] 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.[26] 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.[27]

The primary reasons for these projected deficits also are shown on the OMS-MISO survey. Large amounts of existing generation capacity are projected to be retired each year while, at the same time, the demand for electricity is projected to increase at an accelerating pace.[28] 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.[29]

MISO has been taking steps to address these projected deficits. For example, on June 6, 2025, MISO submitted a proposal to FERC to establish an Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term. This proposal was approved by FERC on July 21, 2025.[30] 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.[31] 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.[32] Consequently, the new ERAS process is unlikely to result in the addition of any new generation capacity in the next few years.

---

[24] *2025 OMS-MISO Survey Results*, OMS and MISO (Updated June 6, 2025) https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf.
[25] *Id.* at 2.
[26] *Id.* at 7.
[27] *Id.* at 9.
[28] *Id.* at 7, 9.
[29] *Id.*
[30] M*idcontinent Independent System Operator, Inc.,* 192 FERC ¶ 61,064 (2025).
[31] 192 FERC ¶ 61,064 at P 84.
[32] *See generally*, *US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply*, S&P Global (May 2025), US gas-fired turbine wait times as much as seven years; costs up sharply | S&P Global. "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."

Order 202-25-3 was preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. Specifically, in 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."[33] President Trump likewise recognized, 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."[34] 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."[35]

The Department's 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, details the myriad challenges affecting the Nation's energy outlook. "Absent 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."[36] The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth. This growth is illustrated by the fact that there are more than twenty AI companies operating in Michigan alone.[37] In addition, as just one example, Consumers has announced an additional 1 GW of new power to a planned hyperscale data center and "continue[s] to see positive momentum with data centers within the 9 GW pipeline . . . ."[38]

Grid operators—including MISO itself—have likewise acknowledged the Nation's current energy crisis. For instance, during a March 25, 2025, hearing before the House Committee on Energy and Commerce, Jennifer Curran, Senior Vice President, Planning and Operations, MISO, testified that "the MISO region faces resource adequacy and reliability challenges due to the

---

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

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

[35] *Id*.

[36] *See also Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, U.S. Department of Energy (July 2025), at 1, https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

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

[38] *See Michigan utility Consumers Energy to provide 1GW of power to new hyperscale data center*, Data Center Dynamics (August 05, 2025), https://www.datacenterdynamics.com/en/news/michigan-utility-consumers-energy-to-provide-1gw-of-power-to-new-hyperscale-data-center/ (quoting Consumers Energy CEO Garrick Rochow).

changing characteristics of the electric generating fleet, inadequate transmission system infrastructure, growing pressures from extreme weather, and rapid load growth."[39] Ms. Curran also described "much stronger growth [in demand for electricity] from continued electrification efforts, a resurgence in manufacturing, and an unexpected demand for energy-hungry data centers to support artificial intelligence."[40] She added, "[a] growing reliability risk is that the rapid retirement of existing coal and gas power plants threatens to outpace the ability of new resources with the necessary operational characteristics to replace them."[41]

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of the Department of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," then the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest."[42] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of the Campbell Plant when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

Such is the case here. As described above, the emergency conditions resulting from increasing demand and accelerated retirements of generation facilities supporting the issuance of Order No. 202-25-3 will continue in the near term and are also likely to continue in subsequent years. This could lead to the potential loss of power to homes and local businesses in the areas that may be affected by curtailments or outages, presenting a risk to public health and safety. Given the responsibility of MISO to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of the Campbell Plant is necessary to best meet the emergency and serve the public interest under FPA section 202(c).

To ensure the Campbell Plant will be available if needed to address emergency conditions, the Campbell Plant shall remain in operation until November 19, 2025.[43]

---

[39] Keeping the Lights On: Examining the State of Regional Grid Reliability Before the House Committee on Energy and Commerce, Subcommittee on Energy, 119th Cong. (Mar. 25, 2025) (statement of Ms. Jennifer Curran, Senior Vice President for Planning and Operations, Midcontinent Independent System Operator), at 5, https://democrats-energycommerce.house.gov/sites/evo-subsites/democrats-energycommerce.house.gov/files/evo-media-document/witness-testimony_curran_eng_grid-operators_03.25.2025.pdf.
[40] *Id.* at 6.
[41] *Id.* at 7.
[42] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b) (2018).
[43] 16 U.S.C. § 824a(c)(4).

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

A. From August 21, 2025, MISO and Consumer Energy shall take all measures necessary to ensure that the Campbell Plant is available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Consumers Energy is directed to comply with all orders from MISO related to the availability and dispatch of the Campbell Plant.

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

C. All operation of the Campbell Plant must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. 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 September 4, 2025, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of the Campbell Plant consistent with this Order. MISO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

E. Consumers 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 the Campbell Plant to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

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

H. This Order shall be effective from 00:00 Eastern Daylight Time (EDT) on August 21, 2025, and shall expire at 00:00 EDT on November 19, 2025, with the exception of applicable compliance obligations in paragraph D.

I. Issued in Norfolk, Virginia at 8:50pm Eastern Daylight Time on this 20th day of August 2025.

____

Chris Wright
Secretary of Energy

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

<u>Michigan Public Service Commissioners</u>
Chairman Dan Scripps
Commissioner Katherine Peretick
Commissioner Shaquila Myers

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 152
CenterPoint Rate Case Discovery Responses

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 (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A PHASE-IN OF RATES, (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, AND NEW AND REVISED RIDERS, INCLUDING BUT NOT LIMITED TO A NEW TAX ADJUSTMENT RIDER AND A NEW GREEN POWER RIDER (3) APPROVAL OF A CRITICAL PEAK PRICING ("CPP") PILOT PROGRAM, (4) APPROVAL OF REVISED DEPRECIATION RATES APPLICABLE TO ELECTRIC AND COMMON PLANT IN SERVICE, (5) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING RELIEF, INCLUDING AUTHORITY TO CAPITALIZE AS RATE BASE ALL CLOUD COMPUTING COSTS AND DEFER TO A REGULATORY ASSET AMOUNTS NOT ALREADY INCLUDED IN BASE RATES THAT ARE INCURRED FOR THIRD-PARTY CLOUD COMPUTING ARRANGEMENTS, AND (6) APPROVAL OF AN ALTERNATIVE REGULATORY PLAN GRANTING CEI SOUTH A WAIVER FROM 170 IAC 4-1-16(f) TO ALLOW FOR REMOTE DISCONNECTION FOR NON-PAYMENT.	**CAUSE NO. 45990**

CENTERPOINT ENERGY INDIANA SOUTH'S RESPONSE TO OUCC'S TWENTY-SIXTH SET OF DATA REQUESTS

Southern Indiana Gas & Electric Company d/b/a CenterPoint Energy Indiana South ("CEI South") pursuant to 170 IAC 1-1.1-16 and the discovery provisions of Rules 26 through 37 of the Indiana Rules of Trial Procedure, by its counsel, hereby submits the following Objections and Responses to the OUCC's Twenty-Sixth Set of Data Requests dated February 1, 2024 ("Requests").

General Objections

All of the following General Objections are incorporated by reference in the response to each of the Requests:

1. The responses provided to the Requests have been prepared pursuant to a reasonable and diligent investigation and search conducted in connection with the Requests in those areas where information is expected to be found. To the extent the Requests purport to require more than a reasonable and diligent investigation and search, CEI South objects on grounds that they include an undue burden or unreasonable expense.

2. CEI South objects to the Requests to the extent they seek documents or information which are not relevant to the subject matter of this proceeding and which are not reasonably calculated to lead to the discovery of admissible evidence.

3. CEI South objects to the Requests to the extent they seek responses and information from individuals and entities who are not parties to this proceeding and to the extent they request the production of information and documents not presently in CEI South's possession, custody or control. CEI South further objects to the Requests to the extent they are (i) vague and ambiguous as to the individuals and entities to whom the Request refer, or (ii) overbroad and not reasonably calculated to lead to the discovery of relevant or admissible evidence.

4. CEI South objects to the Requests to the extent they seek an analysis, calculation, or compilation which has not already been performed and which CEI South objects to performing.

5. CEI South objects to the Requests to the extent they are vague and ambiguous and provide no basis from which CEI South can determine what information is sought.

6. CEI South objects to the Requests to the extent they seek information outside the scope of this proceeding, and as such, the Requests seek information not reasonably calculated to lead to the discovery of relevant or admissible evidence.

7. CEI South objects to the extent the Requests purport to require production of (a) information in a particular format; (b) multiple copies of the same document; (c) additional copies of the same document merely because alterations, notes, comments, or other material appear thereon when such other material is not material or relevant; and (d) copies of the same information in multiple formats on the grounds that it is irrelevant, overbroad, unreasonably burdensome and not required by the Commission rules and inconsistent with practice in Commission proceedings.

8. CEI South objects to the Requests to the extent they solicit copies of voluminous documents.

9. CEI South objects to the Requests to the extent the discovery sought is unreasonably cumulative or duplicative; or is obtainable from some other source that is more convenient, less burdensome, or less expensive.

10. CEI South objects to the Requests to the extent the burden or expense of the proposed discovery outweighs its likely benefit, taking into account the needs of the case, the amount in controversy, the parties' resources, the importance of the issues at stake in litigation, and the importance of the proposed discovery in resolving the issues.

11. CEI South objects to the Request on the grounds that it is overbroad, unreasonably burdensome and seeks information that is largely irrelevant to the subject matter of this proceeding.

12. CEI South objects to the Requests to the extent they seek information that is confidential, proprietary, competitively sensitive and/or trade secret.

13. The responses constitute the corporate responses of CEI South and contain information gathered from a variety of sources. CEI South objects to the Requests to the extent they request identification of and personal information about all persons who participated in responding to each data request on the grounds that it is overbroad, unreasonably burdensome and irrelevant given the nature

and scope of the requests and the many people who may be consulted about them. CEI South further objects to the Requests to the extent they purport to require identification of a witness who can answer questions regarding the substance of or origination of information supplied in each response on the ground that CEI South has no obligation to call witnesses to testify as to information provided in discovery.

14. CEI South objects to the Requests to the extent they seek information that is subject to the attorney-client, work product, settlement negotiation or other applicable privileges. CEI South further objects to the Requests to the extent they purport to require the creation of a privilege log on the grounds that given the extremely expedited and informal nature of discovery in this proceeding, contemporaneous privilege logs are inappropriate. CEI South objects to the Requests on the grounds they are unreasonably burdensome, overbroad, inconsistent with discovery practices in Commission proceedings and inconsistent with the informal discovery process applicable to this proceeding.

15. CEI South assumes no obligation to supplement these responses except to the extent required by Ind. Tr. R. 26(E) (1) and (2) and objects to the extent the instructions and/or Requests purport to impose any greater obligation. CEI South denies that Ind. Tr. R. 26(E)(3) applies to the Requests.

Subject to and without waiver of the general and specific objections set forth herein, CEI South responds to the Requests in the manner set forth below.

Data Requests – Set 26

Q 26.1: According to Attachment CMB-1, CEI South (Gas & Electric) had a $779,891,000 long-term debt payable to Vectren Utility Holdings ("VUH") as of 12/31/2022. Petitioner's Exhibit No. 20, Schedule D-2 reflects a zero balance VUH long-term debt (line 38 of Excel file) as of 12/31/2025.

a) Does this indicate Petitioner's intention to refinance the VUH long-term debt with third party long-term debt? If no, please explain why VUH long-term debt is zero as of 12/31/2025.

b) When does Petitioner expect to refinance or otherwise eliminate the VUH long-term debt?

c) Has this elimination (or refinancing) of VUH long-term debt occurred as of 12/31/2023? Please explain.

Response:

a) Yes. As Petitioner issues new third-party long-term debt, it is repaying borrowings from its parent company.
b) Petitioner expects to refinance the VUH long-term debt by the end of 2025.
c) $255,587,000 of VUH long-term debt remains outstanding as of 12/31/2023.

Q 26.2: According to Attachment SEG-3, the Statement of Cash Flows for CEI South (Gas & Electric), there are no cash outflows reflected for intercompany long-term debt in either 2024 or 2025. Does this indicate Petitioner's intention to refinance or otherwise eliminate VUH long-term debt in 2023? Please explain.

Response: As stated in CEI South's Response to OUCC DR 26.1.b (above), CEI South (Gas & Electric) plans to pay down the full balance of VUH long-term intercompany debt in 2025. Please see the attachments listed below. The Company will file corrections to Petitioner's Exhibit No. 3, Attachment SEG-2 & Attachment SEG-3 to show the cash outflow in 2025 to reflect the full paydown of the intercompany long-term debt.

Attachment:

- 45990 OUCC DR26 26.2_Corrected Pet. Ex. No. 3, Att. SEG-2.xlsx
- 45990 OUCC DR26 26.2_Corrected Pet. Ex. No. 3, Att. SEG-3.xlsx

Q 26.3: Is the VUH long-term debt interest bearing? If yes, what is the interest rate or rates on this debt? If no, please explain why not.

Response: Yes, the VUH long-term debt is interest bearing. Of the $255,587,000 VUHI long-term debt outstanding as of 12/31/2023, $75,000,000 has an effective rate of 1.72%; $106,000,000 has an effective rate of 1.21%; and $74,587,000 has an effective rate of 3.315031%.

Q 26.4: Please state the total operating expenses to operate Culley Unit 2 for each of the calendar years 2020, 2021, 2022, and 2023. This information should be provided by FERC Account for each year in Excel format with formulas intact and cells unlocked.

Response: Please refer to the attachment listed below. Note that due to differences in the way data is stored and presented in Oracle versus SAP, the data for periods prior to July 2021 may not be directly comparable to data for periods after July 2021.

Attachment:

- 45990 OUCC DR26 26.4_FBC2 Operating Expense.xlsx[1]

[1] Information for 2023 is limited to January through September since October through December books have not yet been closed. Information for October through December 2023 can be provided upon request after books have closed.

Q 26.5: Regarding Schedule C-3.33, does the $2,865,574 of operating expenses represent the operating costs for Culley Unit 2 as forecasted for the future test year (2025)? If no, please identify the time period these operating expenses pertain to.

Response: No; the $2,865,574 of operating expenses on Schedule C-3.33 represents the forecasted costs associated with Culley Unit 2 that will be eliminated upon its retirement. Note that the retirement of Culley Unit 2 does not fully eliminate the common expenses that have been allocated to Culley Unit 2 prior to its retirement. The $2,865,574 operating expense includes $2,270,673 for Culley Unit 2 direct cost and $594,901 Culley Unit 2 common costs that are related and allocated to Culley Unit 2 operations.

Q 26.6: Did Petitioner forecast increased operating expenses compared to the base period for its Culley Unit 2 plant through the 12 months ending 12/31/2025? If yes, please state the 2022 operating expenses to operate Culley Unit 2 and the additional costs forecasted for each of the years, 2023, 2024, and 2025 by FERC Account. If no, please explain why no increased operating expenses were forecasted for Culley Unit 2.

Response: No, CEI South did not forecast increased operating expenses to operate Culley Unit 2 compared to the base period. During the forecasting process, CEI South did not identify any needs that would drive up the 2025 operating expenses compared to the base period.

Q 26.7: The Internal Revenue Code currently allows taxable entities to deduct certain costs as repair deductions for tax purposes even though these costs were capitalized for book purposes. Does Petitioner deduct repair deductions for Federal Income Tax purposes that were capitalized for book purposes? Please explain. If yes, please state the repair deduction taken for federal income tax purposes associated with or allocated to CEI South Electric for each of the calendar years 2019, 2020, 2021, 2022, and 2023.

Objection: CEI South objects to the Request on the grounds and to the extent the Request seeks information that is trade secret or other proprietary, confidential, and competitively sensitive business information of CEI South, its customers, or third parties. CEI South has made reasonable efforts to maintain the confidentiality of this information. Such information has independent economic value and disclosure of the requested information would cause an identifiable harm to Petitioner, its customers, or third parties. The responses are "trade secret" under law (Ind. Code § 24-2-3-2) and entitled to protection against disclosure. See also Indiana Trial Rule 26(C)(7). All responses containing designated confidential information are being provided pursuant to nondisclosure agreements between Petitioner and the receiving parties.

Response: Subject to and without waiving the foregoing objection, CEI South provides the following response: Yes, the Petitioner deducts repairs and maintenance costs that were capitalized for book purposes on its Federal Income Tax return and provision. Please see below for the repairs and maintenance deduction attributable to CEI South Electric in calendar years 2019, 2020, 2021, 2022 and 2023:

- 12/31/2019: [redacted]
- 12/31/2020: [redacted]
- 12/31/2021: [redacted]
- 12/31/2022: [redacted]
- 12/31/2023: [redacted]

Q 26.8: Regarding the direct testimony of Matthew A. Rice, Pet.'s Ex. No. 19, Attachment MAR-1, page 117-118, please provide calculation support for the following proposed amounts.

a) Reliability costs for the non-fuel related purchase power of $20,583,262.
b) Interruptible Sales billing credit of $725,000
c) Environmental Emission Allowances of $3,519,952.
d) Wholesale power marketing sales of $21,723,254.
e) BAMP Rate Backup generation capacity services revenue of $201,960.

Objection: CEI South objects to the Request on the grounds and to the extent the Request seeks information that is trade secret or other proprietary, confidential, and competitively sensitive business information of CEI South, its customers, or third parties. CEI South has made reasonable efforts to maintain the confidentiality of this information. Such information has independent economic value and disclosure of the requested information would cause an identifiable harm to Petitioner, its customers, or third parties. The responses are "trade secret" under law (Ind. Code § 24-2-3-2) and entitled to protection against disclosure. See also Indiana Trial Rule 26(C)(7). All responses containing designated confidential information are being provided pursuant to nondisclosure agreements between Petitioner and the receiving parties. "HIGHLY CONFIDENTIAL – FOR ATTORNEYS' EYES ONLY" information is provided pursuant to non-disclosure agreements between CEI South and the receiving parties and is solely for the receiving parties' attorneys to review.

Response: Subject to and without waiver of the foregoing objection, CEI South responds as follows:

a) Please see the attachments listed below: $2,026,462 is located on the RCRA 21-PJM Forecast tab in the first attachment; $5,697,000 is included for OVEC Capacity (see the second attachment); and $12,859,800 is included for capacity purchases (see the third attachment).
b) Please see CEI South's Response to 45990 OUCC DR 22.2(c)(I). There is not a calculation to support this amount. There is an estimated [redacted] of available DR, and CEI South received a bid for DR aggregation as a part of its most recent IRP for [redacted] per MW. $725,000 is [redacted].
c) Please see the attachment listed below.
d) Please see the confidential attachment provided in CEI South's Response to SABIC DR03 3.12: 45990 SABIC DR03 Q3.12 (HIGHLY CONFIDENTIAL – ATTORNEYS' EYES ONLY)_WPM.xlsx[2].
e) Please see Schedule E-4.1, Confidential,[3] page 5, line 14 column (G). [redacted] backup kW times 9.8 days of backup times $0.297 CONE per kw per day.

---

[2] This file contains information designated as "Highly Confidential – Attorneys' Eyes Only" and, pursuant to the Nondisclosure Agreement between CEI South and certain parties to this case must be restricted from any disclosure to anyone outside of attorneys for those parties who have signed the agreement to be bound.
[3] The Confidential Revenue Model Workpaper contains information designated as "Highly Confidential – Attorneys' Eyes Only" and, pursuant to the Nondisclosure Agreement between CEI South and certain parties to this case must be restricted from any disclosure to anyone outside of attorneys for those parties who have signed the agreement to be bound.

Attachments:

- 45990 OUCC DR 26 26.08a_RCRA 21 PJM Forecast through 2028.xlsx
- 45990 OUCC DR26 26.08a (CONFIDENTIAL)_2025 OVEC Demand Projection.xlsx
- 45990 OUCC DR26 26.08a_IE Capacity Forecast 2025.xlsx
- 45990 OUCC DR26 26.08c_NOX Costs 2025.xlsx

Q 26.9: Regarding the direct testimony of Matthew A. Rice, Pet.'s Ex. No. 19, Attachment MAR-1, pages 117-118, please provide a month by month forecasted breakdown of Phase 1 of the following.

a) Reliability costs for the non-fuel related purchase power costs.
b) Interruptible Sales billing credit amount.
c) Environmental Emission Allowances used by retail customers.
d) Wholesale Power Marketing sales amount.
e) Retail portion of the margin from Environmental Emission Allowance sales for the period.
f) BAMP Rate Backup generation capacity services revenue for the period.

Objection: CEI South objects to the Request on the grounds and to the extent the Request seeks information that is trade secret or other proprietary, confidential, and competitively sensitive business information of CEI South, its customers, or third parties. CEI South has made reasonable efforts to maintain the confidentiality of this information. Such information has independent economic value and disclosure of the requested information would cause an identifiable harm to Petitioner, its customers, or third parties. The responses are "trade secret" under law (Ind. Code § 24-2-3-2) and entitled to protection against disclosure. See also Indiana Trial Rule 26(C)(7). All responses containing designated confidential information are being provided pursuant to nondisclosure agreements between Petitioner and the receiving parties.

Response: Subject to and without waiver of the foregoing objection, CEI South responds as follows: Where possible monthly 2025 information is provided in OUCC 26.8 for the test year. CEI South has proposed these base amounts, which will remain the same in Phase 1 through Phase 3.

a) Please see 45990 OUCC DR 26.8a (above).
b) Please see 45990 OUCC DR 26.8b (above).
c) Please see 45990 OUCC DR 26.8c (above).
d) Please see 45990 OUCC DR 26.8d (above).
e) CEI South does not plan to sell any environmental emission allowances in 2025.
f) Please see 45990 OUCC DR 26.8e (above).

Q 26.10: Regarding the direct testimony of Matthew A. Rice, Pet.'s Ex. No. 19, Attachment MAR-1, pages 117-118, please provide a month-by-month forecasted breakdown of Phase 2 of the following.

a) Reliability costs for the non-fuel related purchase power costs.
b) Interruptible Sales billing credit amount.
c) Environmental Emission Allowances used by retail customers.
d) Wholesale Power Marketing sales amount.
e) Retail portion of the margin from Environmental Emission Allowance sales for the period.
f) BAMP Rate Backup generation capacity services revenue for the period.

Response: Please see CEI South's Response to 45990 OUCC 26.9 (above).

Q 26.11: Regarding the Petitioner's Financial Exhibit No. 20, Schedule C3.2, sponsored by witness Chrissy M. Behme, please explain why the increase in TDSIC O&M expense of $27,779 is included in both line 4 and line 7. What purpose is served by this O&M expense adjustment?

Response: The Petitioner's Exhibit No. 20 calculates total revenues for test year 2025, which includes the projected revenue requirement for the TDSIC mechanism. The TDSIC O&M is part of the revenue requirement, and since it is a pass-through cost, it is subsequently removed from the adjustment. It has a net zero impact on net operating income.

Q 26.12: Regarding the Petitioner Financial Exhibit No. 20, Workpaper C3.2a, sponsored by witness Chrissy M. Behme, specifically, the “Large Customer Adjustment – investment” of $1,330,663 and “Large Customer Adjustment – Expense” of $24,507,

a) Please provide how these amounts were calculated.
b) Please provide a schedule support for the periods in which these large customer adjustments are forecasted to take place.
c) Please provide an explanation for how these adjustments are part of the overall TDSIC annualization adjustment.

Objection: CEI South objects to the Request on the grounds and to the extent the Request seeks information that is trade secret or other proprietary, confidential, and competitively sensitive business information of CEI South, its customers, or third parties. CEI South has made reasonable efforts to maintain the confidentiality of this information. Such information has independent economic value and disclosure of the requested information would cause an identifiable harm to Petitioner, its customers, or third parties. The responses are “trade secret” under law (Ind. Code § 24-2-3-2) and entitled to protection against disclosure. See also Indiana Trial Rule 26(C)(7). All responses containing designated confidential information are being provided pursuant to nondisclosure agreements between Petitioner and the receiving parties. “HIGHLY CONFIDENTIAL – FOR ATTORNEYS’ EYES ONLY” information is provided pursuant to non-disclosure agreements between CEI South and the receiving parties and is solely for the receiving parties’ attorneys to review.

Response: Subject to and without waiver of the foregoing response, CEI South responds as follows:

a) These amounts represent the projected 2025 TDSIC revenues [redacted] based on their expected consumption.
b) Please see Cells P61 and P64 of tab “[redacted]” within 45990_CEI South_Confidential Revenue Model Workpaper.xlsx.[4]
c) The TDSIC related adjustments on Schedule C3.1 and the total adjustment on Schedule C3.2 will net to the total TDSIC annualized adjustment of $1,627,665. The TDSIC only portion of the adjustment on Schedule C3.1 is found on WP-C2.1c lines 25 and 26, column B. This schedule and workpaper can be found within the 45990_CEI South_No 20 Financial Exhibit, as well as within 45990_CEI South_Confidential Revenue Model Workpaper.[5]

---

[4] The Confidential Revenue Model Workpaper contains information designated as “Highly Confidential – Attorneys’ Eyes Only” and, pursuant to the Nondisclosure Agreement between CEI South and certain parties to this case, must be restricted from any disclosure to anyone outside of attorneys for those parties who have signed the agreement to be bound.
[5] See Footnote 4, supra.

Dated: February 12, 2024

As to objections only,

Kelly M. Beyrer

Heather A. Watts, Atty. No. 35482-82
Jeffery A. Earl, Atty. No. 27821-64
Alyssa N. Allison, Atty. No. 38083-82
Kelly M. Beyrer, Atty. No. 36322-49
Southern Indiana Gas and Electric Company
d/b/a CenterPoint Energy Indiana South

211 NW Riverside Drive	101 West Ohio St. Ste. 450
Evansville, IN 47708	Indianapolis, IN 46204
(812) 491-5119	(317) 260-5399

heather.watts@centerpointenergy.com
jeffery.earl@centerpointenergy.com
alyssa.allison@centerpointenergy.com
kelly.beyrer@centerpointenergy.com

Nicholas K. Kile, Atty. No. 15203-53
Hillary J. Close, Atty. No. 25104-49
Lauren M. Box, Atty. No. 32521-49
Lauren Aguilar, Atty No. 33943-49
BARNES & THORNBURG LLP
11 South Meridian Street
Indianapolis, Indiana 46204
Kile Telephone: (317) 231-7768
Close Telephone: (317) 231-7785
Box Telephone: (317) 231-7289
Aguilar Telephone: (317) 231-6474
Fax: (317) 231-7433
nicholas.kile@btlaw.com
hillary.close@btlaw.com
lauren.box@btlaw.com
lauren.aguilar@btlaw.com

Attorneys for CEI South Southern Indiana Gas & Electric Company d/b/a/ CenterPoint Energy Indiana South

Distribution to the Following Parties:

CEIS Industrial Group
Todd A. Richardson
Tabitha Balzer
LEWIS KAPPES, P.C.
One American Square, Suite 2500
Indianapolis, IN 46282
TBalzer@lewis-kappes.com
TRichardson@lewis-kappes.com

Courtesy Copy to:
Ellen Tennant
etennant@lewis-kappes.com

OUCC
T. Jason Haas
Adam Kashin
115 W. Washington Street, Suite 1500 South
Indianapolis, IN 46204
thaas@oucc.in.gov
akashin@oucc.in.gov
infomgt@oucc.in.gov

CAC
Jennifer A. Washburn
jwashburn@citact.org

Courtesy Copy to:
Reagan Kurtz
rkurtz@citact.org

SABIC
Nikki G. Shoultz
Kristina K. Wheeler
Bose McKinney & Evans LLP
111 Monument Circle, Ste 2700
Indianapolis, IN 46204
nshoultz@boselaw.com
kwheeler@boselaw.com

		Amount	Amount	Amount	Amount
	Company Code	0599	0599	0599	0599
	Fiscal Year	2020	2021	2022	2023 through Sept
FERC Account		$	$	$	$
4081	Other Taxes-Non-Inc	-	27,040.66	67,640.83	40,275.65
4265	Other Deductions	-	-	-	40.30
5000	Oper Supv & Eng	-	223,481.84	358,518.65	202,153.88
5060	Misc Steam Pwr Exps	-	20,316.56	32,592.62	18,377.64
5100	Maint Suprv & Eng	177,466.34	204,990.48	260,740.80	147,020.95
9250	Injuries & Damages	-	441.23	1,408.12	679.59
9260	Empl Pensions&Ben	-	88,674.11	232,965.11	116,417.09
5130	Maint of Elec Plant	-	51,919.64	56,488.74	48,577.90
5120	Maint of Boiler Plt	833,316.39	887,907.28	793,461.69	480,310.53
5020	Steam Exp	733,871.50	484,400.19	228,145.68	122,634.98
5050	Electric Exp	486,956.83	317,563.00	306,087.77	185,586.58
	Total	**2,231,611.06**	**2,306,734.99**	**2,338,050.01**	**1,362,075.09**

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 153
Wayne Games 2018 Testimony

FILED
September 10, 2018
INDIANA UTILITY
REGULATORY COMMISSION

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY

D/B/A

VECTREN ENERGY DELIVERY OF INDIANA, INC.

CAUSE NO. 45052

PUBLIC REBUTTAL TESTIMONY

OF

WAYNE D. GAMES

VICE PRESIDENT OF POWER SUPPLY

SPONSORING PETITIONER'S EXHIBIT NO. 4-R,
ATTACHMENTS WDG-1R THROUGH WDG-4R

REBUTTAL TESTIMONY

OF

WAYNE D. GAMES

VICE PRESIDENT OF POWER SUPPLY

Q. Please state your name and business address.

A. My name is Wayne D. Games, and my business address is One Vectren Square, Evansville, Indiana 47708.

Q. Did you provide Direct Testimony on behalf of Vectren South in this Cause?

A. Yes.

Q. Are you sponsoring any exhibits in support of your testimony?

A. Yes. I am sponsoring the following exhibits:

- Petitioner's Exhibit No. 4-R, Attachment WDG-1R, a list of Brown Corrosion Projects from 2008-2018;
- Petitioner's Exhibit No. 4-R, Attachment WDG-2R, Indianapolis Power & Light's ("IPL") Harding Street Station Energy Information Administration ("EIA") Data.
- Petitioner's Exhibit No. 4-R, Attachment WDG-3R, Timeline For CCGT Construction
- Petitioner's Exhibit No. 4-R, Attachment WDG-4R, Capacity of Unfired CCGT

Q. Were the exhibits identified above prepared or assembled by you or under your direction or supervision?

A. Yes.

Q. What is the purpose of your Rebuttal Testimony in this proceeding?

A. Various witnesses from the Indiana Office of Utility Consumer Counselor ("OUCC"), Alliance Coal, LLC ("Alliance Coal"), the Indiana Coal Council ("ICC") and the Citizens Action Coalition/Valley Watch/Sierra Club ("Joint Intervenors") allege that customers face fewer risks if Southern Indiana Gas and Electric Company, Inc. d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren South" or the "Company") retains its aging, uncompetitive, existing generation fleet for some period of time beyond 2024 rather than replacing several of these units with a highly efficient combined cycle gas plant ("CCGT"). While several other Vectren South witnesses will explain why these parties have reached the wrong conclusion, my testimony will focus on the significant risks presented from an operational standpoint by trying to keep these units running beyond 2024. I will explain the competitive challenges faced by our units in the Midcontinent Independent System Operator ("MISO") energy market, the risks with continued reliance on these units, and explain why the efficient CCGT the Company is seeking approval to construct presents lower risks. I also:

- Discuss issues with converting the Brown units from coal to gas fired.
- Discuss the project timeline and risks associated with delaying until the next IRP.
- Address why the preferred IRP plan offers diversity and why it makes sense to duct fire the proposed CCGT.
- Show the reduction in annual wholesale power margin due to Vectren South coal units not being competitive.
- Respond to criticisms from the OUCC that Vectren South's cost estimate is not reliable.
- Discuss recommendations made by the Industrial Group relating to contracting for construction of a CCGT.
- Explain that Vectren South did consider alternative scrubber technology at A.B. Brown.

I. Risk Is Not Mitigated By Delaying The Decision

Q. Can you summarize the position of the other parties regarding Vectren South's proposal?

A. Except for the Industrial Group, who represents specific Indiana customers, the other parties all contend that Vectren South should minimize risk by sticking with its existing resources in one form or another. ICC, Sunrise Coal and Alliance Coal, not surprisingly, want to keep the A.B. Brown facility ("Brown") burning coal, for as long as reasonably possible. This protects their own economic interests in ensuring continued demand for their product. The OUCC urges Vectren South to convert one or both of the Brown baseload units to utilize natural gas, continue operating the remainder of the generation fleet and wait for more certainty. The Joint Intervenors criticize Vectren South's modeling assumptions and make no specific recommendation beyond denial of our requested CPCNs.

Q. Is there a common basis these parties rely on to justify continuing with Vectren South's existing generation resources?

A. Yes. The parties all allege that retiring Vectren South's smaller coal units and building a larger gas plant is risky for customers. Other Vectren South witnesses discuss the modeling Vectren South has done and the assessment of risk involved in that modeling. In my role as Vice President of Power Generating, I am very familiar with the existing Company generation facilities the parties propose to keep running. There are numerous risks with continuing to rely on these units for the foreseeable future that the other parties ignore. I will discuss these risks and explain why Vectren South's proposed CCGT better mitigates customers' risk.

A. Risks From Continuing Vectren South's Heavy Reliance on Coal-Fired Generation

Q. What are the primary risks associated with continuing to operate a coal heavy fleet?

A. A coal heavy fleet, especially one dominated by small, aging plants, is exposed to risks from future environmental regulations, poor MISO market performance and reliability.

Q. Please discuss the risks created by environmental regulations applicable to Vectren South's existing generation fleet.

A. Coal plants face significant risks of rising costs and reduced efficiency from future environmental regulations. Vectren South has already made significant environmental control investments and the variable costs to operate this equipment places further pressure on the economics of the Company's generating facilities. For example, Vectren South spends in excess of [redacted] (an approximate [redacted] premium per MWHr generated) for the chemicals to remove sulfur dioxide (SO_2), nitrogen oxide (NO_x), sulfuric acid (H_2SO_4), particulate and mercury at Brown. The injection of sodium to control for H_2SO_4 at Brown has caused plugged nozzles and sodium build up in duct work necessitating outages to correct. In 2018, the Company must purchase seasonal NO_x allowances for Brown at a cost of \$150-\$350 per allowance. Brown's water treatment costs associated with its National Pollution Discharge Eliminations System ("NPDES") permit have increased to sample for several constituents and treat for mercury, oil and grease, suspended solids, total residual chlorine and copper and iron. Starting in April of 2020, Brown will incur more cost associated with treating water discharge for selenium, chlorides and copper.

As Company witness Retherford discusses, there continue to be risks of further environmental regulation as administrations change. This includes carbon regulation, stricter NPDES limits and the Environmental Protection Agency ("EPA") ratcheting down on SO_2 and NO_x allowance values and/or potentially changing these and other emission limits associated with coal fired units. The newly announced replacement to the Clean

Power Plan ("CPP") appears to require incremental efficiency improvements at coal fired power plants, necessitating additional capital investments. Vectren South improved the efficiency of Brown by installing dense packs in 2012 and 2013 at an incremental capital cost of $28.6 million. There continues to be a push by some to regulate carbon through a tax or other approach. This creates the risk of additional incremental costs for coal plants because of their significant carbon emissions.

Q. Please discuss the risks for coal-fired generation plants created by the MISO market, intermittent renewable resources, and low natural gas costs.

The MISO energy market dispatches the lowest cost generation required to maintain system reliability, giving MISO members the lowest cost energy available. Highly efficient CCGT natural gas plants and renewable resources are lower cost than the Company's small coal plants, contributing to falling capacity factors for the smallest least efficient coal units. These units must drop to minimum output or cycle off during the off-peak hours because they are higher cost than other resources, driving even higher production costs. These factors have a direct impact on customers. On a daily basis, Vectren South offers all of its units into the MISO market and purchases all of its customers' needs for electricity from the MISO market. On days when the Company's units are dispatched by MISO, the cost of the energy Vectren South purchases to serve its customers can be offset in part by the revenues paid by MISO for the energy sold into the MISO market. The higher costs associated with the low efficiency of Vectren South's coal units greatly reduces the opportunity for additional revenues used to reduce customer daily energy costs. Vectren South's units are particularly vulnerable because they are the smallest and some of the lowest efficiency (highest heat rate) units in the State. **Figure 1** shows the nameplate capacity of Vectren South's coal units compared to other Indiana Investor Owned Utilities ("IOU's") coal units while **Figure 2** shows the efficiency or heat rate comparison of Vectren South's coal fleet compared to other Indiana IOU coal units. These Figures show only units anticipated to still be in operation in 2023. A lower heat rate indicates higher efficiency.

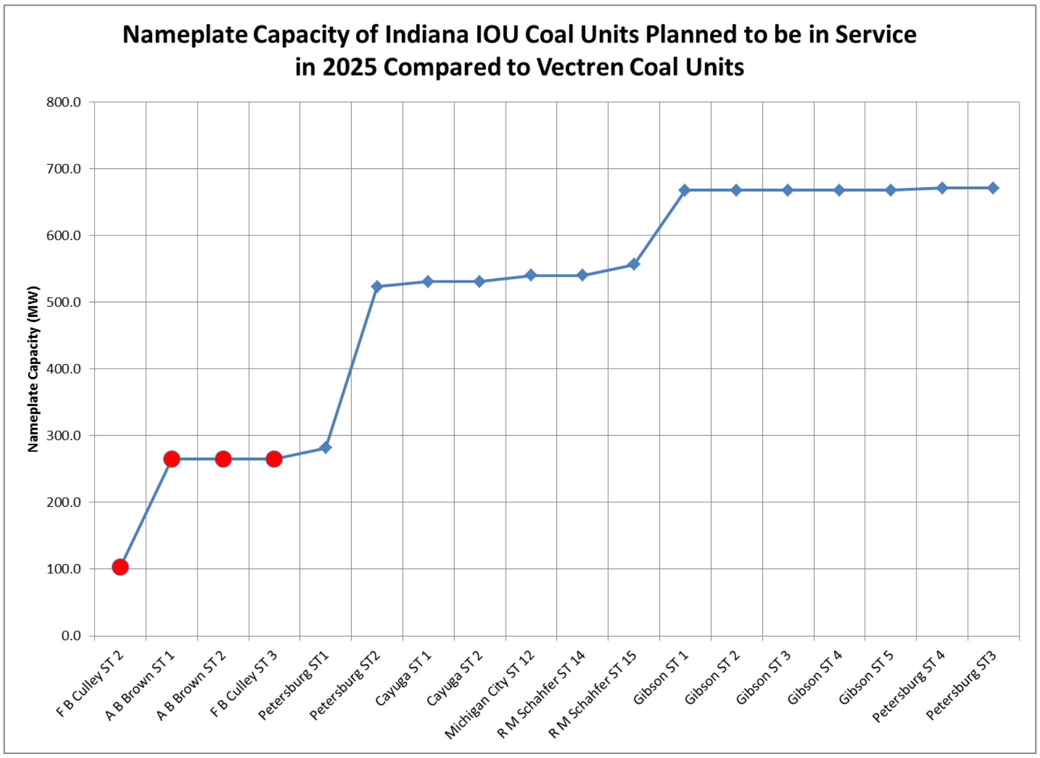


Figure 1

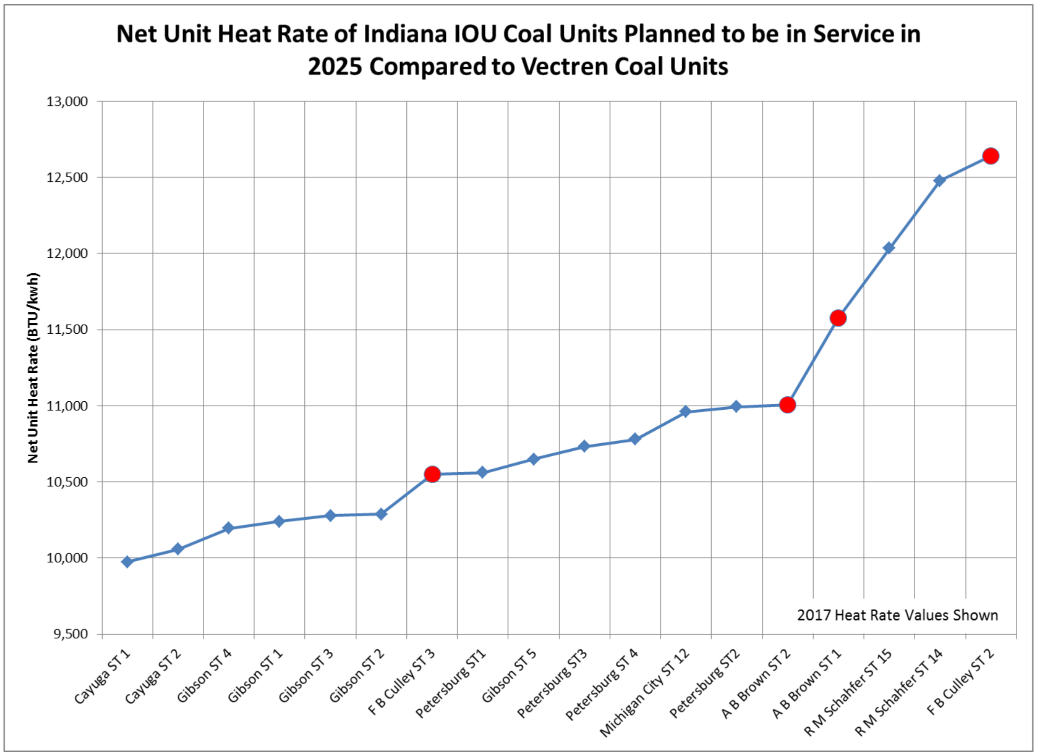


Figure 2

As shown by these Figures, maintaining Culley Units 2&3 and Brown Units 1&2 leaves Vectren South with the four smallest IOU coal units within the State. Except for Culley Unit 3, continuing to rely on these units would leave Vectren South's customers with among the most inefficient coal units within the State. Note that in the interest of maintaining diversity, Vectren South's preferred plan maintains Culley Unit 3 due to it being the largest most efficient coal unit in the current fleet.

Q. Please explain your concerns with the coal units being operated in a manner they were not designed for.

A. Vectren South's coal units were designed as base-load units, meaning that they were designed to continually run at relatively stable levels of output to serve the base needs of our customers. At the time they were constructed, the Company's coal units were very low cost and provided the most cost effective way to meet the demands of customers.

The advancement of technology and the dramatic reduction in the cost and abundance of natural gas have changed the dynamics for coal-fired units. The MISO "Day-Ahead" market dispatches generators that have been offered into the market (starting with the lowest cost source/unit) against hourly forecasted demand. The hourly market energy price is established by the last unit required to meet the demand. Renewables are typically dispatched first because of their low variable operation and maintenance ("O&M") costs and tax incentives that encourage renewable resources to be dispatched whenever they are available. This leaves other forms of generation to fill the gap between what intermittent renewable resources can produce and the changing requirements of retail customers on a real time basis. This gap which can fluctuate rapidly and widely is filled in the MISO "Real-Time" energy market by sources that can adjust (ramp) output quickly.

Due to the production cost (low efficiency) of Vectren South's coal units they are called upon to cycle off/on and ramp up/down more often than more efficient lower cost generation sources including larger super critical coal units. Cycling particularly impacts the Company's generating resources. This has the largest impact on units like Culley Unit 2 and Brown Units 1&2 as they are the smallest and more expensive coal units in the MISO stack. My Direct Testimony referenced a June 3, 2015 U.S. Department of Energy ("DOE") report on coal-fired generation titled "Impact of Load Following on the Economics of Existing Coal Plant Operations". The report recognized that "generally an increase in frequent ramping and/or shutdowns decreases the component life through damage caused by creep, fatigue, thermal shock, acid induced corrosion, erosion, and other stresses".[1] I discussed specific issues outlined in the report and an example of

[1] Creep damage occurs in metals and alloys after prolonged exposure to stress at elevated temperatures.

Solid Particle Erosion ("SPE") that occurred on Brown Unit 1 that caused a 3 month outage and $3.8M repair during the summer of 2016. Since submitting my original testimony other studies have been completed addressing the ramping and cycling issues on coal units designed for baseload operation and we've actually discovered more issues at the Brown plant due to increased cycling over the past 9 years. These include issues that will require more frequent inspections and extensive repairs or future replacement of costly high energy steam piping to ensure reliability of the plant as well as the safety of employees.

Q. How does this create additional risk for Vectren South customers?

A. There is expected to be a significant increase in the Equivalent Forced Outage Rate ("EFOR") and reduction in reliability over time. Vectren South's own experience demonstrates the risk that incremental capital, reduced plant life and increasing outages may result from trying to operate the Company's coal units in a fashion they were not designed for over an extended time period.

Q. Would efforts from the Federal government to monetize coal's resiliency attributes change Vectren South's concerns with continued reliance on its coal units?

A. Not as it is currently being proposed. ICC witness McConnell is referring to a draft memo of the Department of Energy ("DOE") that discussed the possible subsidization of certain coal and nuclear facilities for a two year period. The memo provided no detail regarding how such subsidization would work, the nature of the monetary benefits, and the identification of units selected to benefit from payments. Regardless of such speculation, Vectren South's plan calls for its coal plants to operate through 2023, well beyond this two year period. The Company's operating region is surrounded by large coal units such as Rockport, Gibson and Petersburg that are not currently scheduled to be retired that would appear to fit more within the DOE's view of resiliency than Vectren South's small coal units.

Q. Do others recognize the same concerns you are raising with continued reliance on coal fired generation?

A. Yes. Just this week a draft report by the National Coal Council ("NCC") entitled "Power Reset: Optimizing the Existing U.S. Coal Fleet to Ensure a Reliable and Resilient Power Grid" became public. ICC witnesses Medine and McConnell, Alliance Coal witness Nasi, and Sunrise Coal witness Dombrowski are all listed authors or committee members. The NCC Report discusses how renewable energy resources impact coal units, and identifies concerns with cycling of coal units, lower revenues for coal units, lower efficiency, and reduced plant life attributable to the same factors I identify for the Company's units. The NCC Report admits that the wear and tear experienced by coal units has led to a point where the reliability of such plants "could be significantly less" and that such cycling conditions result in "increased capital expenditures, increased O&M costs, increased outages and higher fuel consumption."

Q. OUCC witness Alvarez contends that Vectren South's coal units performed at par in some years, and even better in other years, than the entire coal fleet of the country. (Public's Exhibit No. 2, pp. 16-17). Does this history of availability support the proposal to just keep running these plants well beyond 2023?

A. No. While I am pleased the OUCC agrees that Vectren South has done such an effective job operating plants, the more pertinent economic question is how well coal-fired generation is performing in the energy markets. The retirement of coal-fired generation facilities is being announced throughout the country because their high-heat rates and limited ability to ramp is rendering them less economic, especially when competing with highly efficient gas plants using low cost gas. **Table 1** shows that Brown Units 1&2 and Culley Unit 2 capacity factors have dropped significantly from 2000-2008 to 2009-2017. **Figure 4** shows the Company's annual Wholesale Power Market ("WPM") margin since 2000, establishing that the Company's units are generating wholesale power sales much less frequently since gas prices began dropping in recent years.

	2000-2008	2009-2017
A.B. Brown 1	72%	52%
A.B. Brown 2	76%	55%
F.B. Culley 2	69%	23%

Table 1

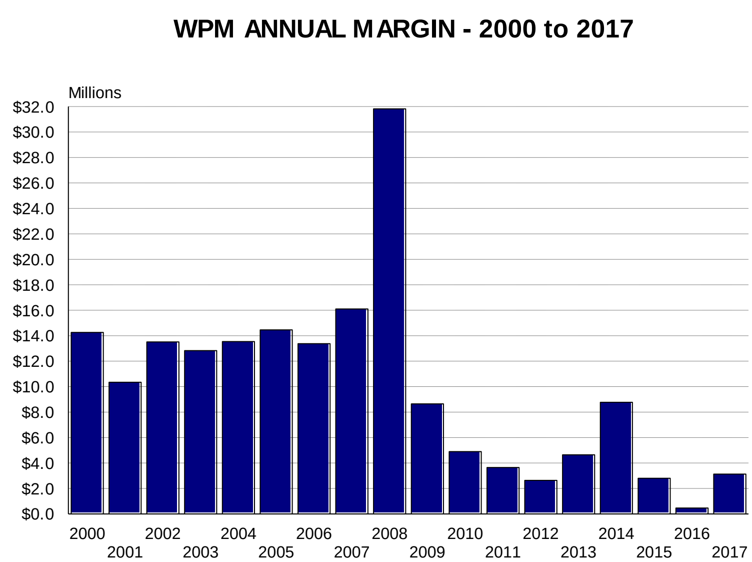


Figure 4

These factors are driving coal plant retirements throughout the country. Data compiled by SNL (S&P Global) shows that 458 coal units constituting over 52 gigawatts ("GWs") of capacity have been retired nationwide since 2012 with 97 of those located in the MISO footprint. Another 85 unit retirements making up another 16 GWs have already been approved for retirement in the U.S. with many others announced but not yet approved. Maintaining a high reliance on aging, small inefficient coal units that require environmental investments and are not designed to provide the flexibility needed to operate in the MISO market is not a good decision for Vectren South customers. Continuing to rely on coal units to provide 95% of our energy would make the Company an extreme outlier when compared to other US investor owned utilities.

Q. OUCC witness Alvarez contends that replacing the Company's existing smaller units with a single CCGT exposes customers to the risk of reliance on a single unit that could have an outage. (Public's Exhibit No. 2, pp. 11 and 16). Do you agree that this represents greater risk compared to operating the existing coal fleet?

A. No. First, having a new unit designed to effectively ramp production provides greater reliability than operating coal units that simply were never intended to operate in response to dynamic MISO price signals. The risk of older coal units being off line due to either economics or equipment failure is the greater risk. Second, if the CCGT experiences an outage, in the short-term the MISO market can provide energy for customers. Buying energy when needed in the short-term does expose customers to price risk, but that is different than basing a long term resource plan (and meeting MISO Planning Reserve Margin ("PRM") requirements) on the availability and price of market capacity.

B. Specific Risks from Reliance on Brown Units 1 and 2

Q. ICC witness Hayet proposes to continue operating Brown until 2023 (for Unit 1) and 2030 (for Unit 2), ICC witness Medine advocates operating them for another ten years while OUCC witnesses urge converting the units to burn natural gas and continuing their operation indefinitely. What is Vectren South's experience with Brown?

A. Although the Brown units are the newest coal units within Vectren South's fleet (they will be 44 and 37 years of age in 2023), only Culley Unit 2 is more expensive to operate and maintain. Brown requires the largest capital investment among Vectren South's fleet to continue reliable operation beyond 2023. Apart from Coal Combustion Residual ("CCR") regulation compliance costs, a key challenge for these units is their dual-alkali scrubbers. Dual-alkali scrubbers require expensive chemicals to lower emissions and create a highly corrosive environment that impacts the scrubbers and other plant equipment. The industry has abandoned the dual-alkali scrubber as a result of these challenges and the Brown scrubbers are the only dual-alkali scrubbers still operated by a utility in the United States.

The corrosive environment created by the dual-alkali scrubbers causes regular damage to the infrastructure necessitating capital investment to repair the damage so the plants can continue to operate. As shown in Petitioner's Exhibit No. 4-R, Attachment WDG-1R, over $32M (an average of over $2.9M annually) has been invested to address Brown's corrosion issues to keep the facility reliable and safe for employees. Even if the scrubbers were replaced, remaining equipment impacted by the scrubbers' corrosive chemicals would require repairs. In 2005, a bridge spanning a Brown Unit 1 storage tank collapsed due to corrosion, shutting the unit down for an extended period of time to make repairs.[2] In 2017, over $1M was spent to rebuild a support structure holding ductwork that carries flue gas between the absorber tower and the chimney. Vectren South developed estimated capital and O&M projections for investments to keep Brown running for purposes of its integrated resource plan ("IRP") modeling, but it is very

[2] A picture of this bridge is labeled as photo 27 in Petitioner's Exhibit No. 4, Attachment WDG-1.

difficult to accurately project the capital and other expenses necessary to keep a plant operating with two scrubbers that are causing so many issues.

The scrubbers are already beyond their 30-year design life. Burns & McDonnell's ("B&McD") assessment of these scrubbers, attached to my direct testimony as Petitioner's Exhibit 4, Attachment WDG-1, concluded that "it would be prudent for Vectren South to retire and/or replace the Brown scrubbers at a total life of 40-45 years maximum, which implies the scrubbers should be retired and/or replaced sometime over the next 5-10 years". ICC witness Hayet accepts this for purposes of his modeling although Ms. Medine appears to advocate for stretching operation even beyond this recommended period. Vectren South is proposing to retire Brown Unit 1 when its scrubber is 44 years old and Brown Unit 2 when its scrubber is 37 years old, well beyond the 30-year design life. From a safety and reliability perspective, I do not agree that it is prudent to push the life of these scrubbers beyond 2023.

Q. OUCC witness Aguilar dismisses Vectren South's concerns with loading fly ash onto barges at Brown by indicating that the Company "may have to investigate the cost to temporarily store fly ash [at Brown] for occasions when barges cannot be loaded." (Public's Exhibit No. 1, pp. 21-22). What would it cost to address this concern?

A. Options and capital cost to modify Brown dry fly ash system were evaluated by Black & Veatch ("B&V") who estimated the price of viable alternatives would be around [redacted] This further demonstrates the costs of trying to keep Brown operating with coal.

Q. Are there other risks with continuing to rely on the Brown units?

A. Yes. Since 2008, the Brown plants and Culley Unit 2 cycle more than any other Vectren South plant because they are not competitive in the MISO energy market. I have already discussed the additional wear and tear this creates for coal-fired units. Several specific issues have been identified at Brown as a result of cycling. Recent assessments of High Energy Piping which transports high pressure steam at Brown show signs of creep damage and other fatigue that will rapidly worsen due to cycling and will require replacement if operated beyond 2023. The Brown Unit 1's super-heater outlet header will need to be replaced due to thermal fatigue and scale build-up. Other welds at Brown show signs of creep damage while others have been determined to be at high risk for creep damage. Creep damage places pipe and welds in a condition that will make them more susceptible to the impacts of cycling. I expect more of these issues as routine inspections are completed over time.

Q. What risk does continuing to rely on Brown create for customers?

A. Based on my experience overseeing Brown's operation, there is a significant risk that capital expenditures to keep Brown operating will turn out to be higher than projected in the IRP modeling, and a very low likelihood that costs will be less. The timeline to replace Brown is a multi-year process and Vectren South may be boxed into making investments in Brown to enable it to continue reliably serving its customers while going through the process to procure reliable replacement generation.

Vectren South will minimize near term (2017-2023) investments previously planned while ensuring adequate reliability is maintained if a CPCN for the new CCGT is approved. Some examples of avoided capital and O&M work that would be required to keep Brown operating beyond 2023 are listed in **Table 2**. Completion of this work will not guarantee avoidance of other equipment failures.

Deferred Investment in Brown Due To Retirement	Cost
Water-Wall tube replacements	[redacted]
Additional cyber security investments	[redacted]
FD Fan overhaul dampers and housing (2)	[redacted]
Unit 2 economizer inlet header replacement	[redacted]
Replacement of insulation and ladding	[redacted]
Major ductwork and expansion joint replacement	[redacted]
Units 1 and 2 boiler chemical cleans	[redacted]
U2 catalyst replacement	[redacted]
Coal handling switchgear replacement	[redacted]
Superheater inlet tubes	[redacted]
Unit 1 superheat outlet header	[redacted]
Unit 1 and 2 coal pipe replacements (all straight runs)	[redacted]
Units 1 and 2 air heater overhauls	[redacted]
Unit 2 480 switchgear to operate plant equipment	[redacted]
Replacing the river well piping	[redacted]
Unit 1 480 switchgear to operate plant equipment	[redacted]
Unit 2 partial cooling tower cell rebuild	[redacted]
Turbine generator overhauls on both units	[redacted]
Total	30,290,000

Table 2

Q. The OUCC contends Vectren South should more thoroughly evaluate converting Brown to burn natural gas. Did Vectren South assess this option?

A. Yes. Vectren South engaged Babcock & Wilcox Co. to prepare an analysis of the coal-to-gas conversion. I agree with OUCC witness Alvarez that Brown could be converted to burn natural gas at a much lower up-front capital cost, but a gas-fired Brown would be very inefficient because of its high heat rate and fuel cost and rarely dispatched. In short, customers would be paying rates for capacity and then largely depending on MISO for energy purchases to actually serve their day to day needs. **Table 3** shows that the fuel cost (example has \$4.00/mmBtu natural gas price) to generate a MWHr from a gas-converted Brown unit is \$20 more expensive than a MWHr generated by the proposed "F" class CCGT.

	Heat Rate	**Fuel cost/MMBtu @ $4/MMBtu Transportation**	**Approximate Fuel cost/ MWHr**
Brown Coal Unit Converted to Gas	11,760	4.00	[redacted]
Proposed CCGT	6,560	4.00	[redacted]

Table 3

Q. Did Vectren South include any coal to gas conversion in its modeling?

A. Yes. Vectren South's initial IRP modeling considered, but did not select as a low cost resource, converting Culley Unit 3 to gas. In response to the OUCC's concerns, Vectren South witness Lind evaluated the total cost to ratepayers of a portfolio that converted Brown to operate on gas. This updated modeling demonstrates that it is more expensive when considering total costs to customers to convert Brown to operate on gas, primarily because of the need to make energy purchases to serve customers because of the high cost and inefficiency of a gas-converted Brown.

Q. Why would a utility convert a coal plant to burn gas given its inefficiency and high cost?

A. Utilities with large generation portfolios sometimes convert smaller coal units to burn gas if they need capacity. These utilities use their large, low cost generating units to serve customer load the majority of the time and cost effectively satisfy capacity needs to satisfy MISO's PRM with gas-converted coal plants.[3] In contrast, converting the Brown units to gas would leave Vectren South without sufficient low cost energy to serve its customers on a daily basis. For this reason, Vectren South's IRP modeling did not consider converting Brown to gas.

[3] Company witness Justin Joiner explains MISO's PRM in more detail. In short, MISO requires market participants to maintain a specified amount of capacity to ensure that the MISO region can satisfy needs experienced during peak periods.

Q. Mr. Alverez points to IPL Harding Street coal to gas conversion as an example of a low cost solution that has been successful. Does IPL's experience suggest converting Brown to a gas burning facility would be a prudent course?

A. No. IPL meets the criteria I just discussed—it has constructed a large new CCGT that can meet the majority of its needs and relies on Harding Street primarily for capacity. According to Harding Street EIA data provided as Petitioner's Exhibit No. 4-R, Attachment WDG-1R, the heat rate at Harding Street increased by approximately 15% and capacity factors have fallen from the 70% range into the teens. Harding Street's capacity factor is actually better than most coal to gas conversions and may indicate that transmission limitation around the Indianapolis area or other factors are helping Harding Street perform better than most coal to gas conversions. There have been 51 coal-to-gas conversions across the U.S. between 2013 and 2018. The majority were small units that converted to avoid high dollar investments to comply with the 2016 Mercury and Air Toxic Standard ("MATS") deadlines. The capacity factor for these units dropped from an average of over 40% to below 5% and heat rates rose from 10,800 to 12,500. Nineteen units in MISO have been converted from coal to gas and their heat rate increased from approximately 11,500 to 15,400 and capacity factors declined from a 60% average to less than 5%. Harding Street, MISO and Vectren South coal to gas conversion information is provided as Petitioner's Exhibit No. 4-R, Attachment WDG-2R.

Q. Are there any other potential costs to customers that Mr. Lind's modeling of gas-converted Brown units did not consider?

A. Yes. Because these units would not run frequently, customers could be exposed to congestion charges for the energy they require. The Locational Marginal Price ("LMP") paid for energy purchased from the MISO market consists of the energy, congestion and line loss.[4] Transmission and distribution systems were designed to serve customers from local generation sources. When energy is imported from long distances, transmission lines can become stressed or overloaded. One way MISO balances the system and ensures reliability of the transmission grid is by assessing a congestion charge component of the LMP to encourage generation to operate (or be constructed) or not operate depending on the needs of the transmission system. Congestion can be positive, increasing the price MISO pays for energy incenting the seller to increase production or negative, which reduces the price MISO pays for energy incenting the seller to reduce or stop production.

Q. Do you have an example of how congestion can impact the LMP of non-localized generation?

A. Yes. Vectren South has two Purchase Power Agreements ("PPAs") in place for wind from Benton County Indiana with Benton County Wind Farm and Fowler Ridge II Wind Farm. **Table 4** shows the average five year congestion component of the LMP paid by Vectren South customers for the two wind farms compared to five year congestion component of local generation at the Brown and Culley locations. The congestion for the wind farms is much higher than for local generation. **Table 5** shows the number of hours that Vectren South has experienced negative LMPs for the two wind farms compared to Brown and Culley over the past 5 years. Note that there is a much higher congestion charge and many more negative LMP hours for generation that is farther from the load it is designated to serve.

[4] LMP is the hourly price for energy set by the last unit needed to meet demand in an area.

Generation Source	Day Ahead Average Congestion Component (Paid By Load) Of The LMP	Real Time Average Congestion Component (Paid By Load) Of The LMP
Brown	[redacted]	[redacted]
Culley	[redacted]	[redacted]
Benton County	[redacted]	[redacted]
Fowler Ridge	[redacted]	[redacted]

Table 4

Generation Source	Day Ahead Hours with Negative Pricing	Real Time Hours with Negative Pricing
Brown	[redacted]	[redacted]
Culley	[redacted]	[redacted]
Benton County	[redacted]	[redacted]
Fowler Ridge	[redacted]	[redacted]

Table 5

C. Risks With Continued Reliance on Culley Unit 2

Q. OUCC witness Aguilar contends Vectren South could continue to operate Culley Unit 2 and utilize the benefits of sharing environmental compliance equipment with Unit 3. (Public's Exhibit No. 1., p. 22). Why is the Company proposing to retire Culley Unit 2?

A. I explained in my Direct Testimony (Petitioner's Exhibit No. 4, p. 21) the reasons why retiring Culley Unit 2 is the best option for customers. Ms. Aguilar has not addressed any of the concerns with continued operation of Culley Unit 2 identified in my Direct Testimony. She relies only upon Culley Unit 2's ability to share environmental compliance equipment with Culley Unit 3, but fails to acknowledge that a minimum of $70 million in additional capital investments are required to continue operating Culley Unit 2 through 2036. In part, this investment is driven because Culley Unit 2 cannot solely rely on Culley Unit 3 for environmental compliance costs. A dry bottom ash system must be installed to comply with CCR and further investments may be required to comply with section 316b of the Clean Water Act (designed to protect fish and other aquatic wildlife at water intake and outfall structures) on the design and operation of the current river intake structure. In addition to these environmental costs, Culley Unit 2's distributed control system ("DCS") is a Honeywell system installed in 2000 and must be updated or replaced because it is obsolete. A few other significant capital investments that would be required to keep Culley Unit 2 operating beyond 2023 include a turbine major overhaul, boiler acid clean, main transformer overhaul/replacement, major boiler component replacement, dry stack ductwork replacement, ID fan discharge ductwork, coal conveyor gallery replacement, boiler/high energy piping condition assessment, air heater basket replacement, continued overhaul of circulating water pumps and traveling water screens, and replacement of two 480-volt motor control center electrical switchgear.

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

D. Risks From Continued Reliance on Warrick Unit 4

Q. What is the basic contractual arrangement related to Warrick Unit 4 with Alcoa?

A. Vectren South and Alcoa are parties to Joint Operating Agreement ("JOA") pursuant to which each has 50% ownership (150 megawatts ("MW") each) in Warrick Unit 4. Warrick Unit 4 came on line in 1970 and will be 54 years old in 2023. The unit sits on Alcoa property along with three other (150 MW each) units referred to as Warrick Units 1-3. Alcoa personnel are responsible for daily operations and maintenance decisions. Vectren South provides input through an Operating Committee that meets regularly.

Q. OUCC witness Aguilar testifies that she does not agree with Vectren's assessment of the risk of continuing to operate under the agreement and she specifically

describes that the OUCC does not agree with Vectren South's "presentation of the agreement." (Public Exhibit No. 1, p. 23). Please respond.

A. Witness Aguilar does not address Vectren South's specific concern that Alcoa has [redacted]. This concern was explained by the Company in the OUCC data request cited by Ms. Aguilar (Public's Exhibit No. 1, p. 23 fn. 31).

The original agreement provided Alcoa [redacted] and a 2001 amendment afforded either party the ability [redacted]. That [redacted] in a 2017 amendment due to ALCOA's corporate reorganization and operational uncertainty described by Company witness Chapman. Capital investments in Warrick Unit 4 must be evaluated in terms of the risk that Alcoa will exercise its [redacted] and, in effect, [redacted]. The decisions that might lead Alcoa to exercise its contractual rights arise from its own business economics and, particularly, the aluminum business.

Q. Are future environmental capital investments in Warrick Unit 4 necessary?

A. Yes. Due to compliance requirements coming in Alcoa's next NPDES permit, it is anticipated that the unit will require a significant capital investment to eliminate the plant's direct discharge to the Ohio River. This would require a Waste Water Treatment facility to treat the FGD waste stream and any process stream entering the ash pond prior to discharge. Also, Alcoa may be required to comply with section 316b of the Clean Water Act under this new permit which could include a reengineered design to the river intake system. Company witness Retherford discusses the Warrick site environmental risks in greater detail.

Q. Are there other factors that warrant against continued reliance on Warrick Unit 4?

A. Yes. Mr. Chapman notes that Vectren South wanted to keep one coal unit to avoid the all gas portfolio modeling demonstrated was the lowest cost portfolio. We focused on our best performing coal unit, Culley Unit 3. Warrick Unit 4 was considered, but the contractual concerns and the unit's performance led us to select Culley Unit 3.

Q. Please describe the performance issues at Warrick Unit 4 that made Culley Unit 3 a more attractive unit for the future.

A. The operating unit itself has become more susceptible to forced outages in recent years. **Table 6** shows that in all but one of the previous six years, the unit's EFOR has been well above the industry average of 8.56% with the last two years being over 17% (over twice the industry average).

	2012	**2013**	**2014**	**2015**	**2016**	**2017**
Warrick Unit 4 EFOR Rate	12.75	11.75	15.2	4.8	17.8	17.3

Source: PowerGADS (MISO) GORP Report
Table 6

Along with boiler tube failures, Alcoa has incurred multiple large mechanical and operational failures contributing to the high EFOR. Recent examples include a prematurely failed selective catalytic reduction ("SCR") catalyst layer, issues with air heater internals, boiler control failures due to DCS feedback and field device failures, and emission restricted shut downs. Warrick Unit 4 is also minimum load restricted (228-350 MWs) due to a failed duct burner on the SCR that maintains the unit's exit gas temperature minimizing unit corrosion due to flu gas reaching acid dew point.

E. Risks from Continued Reliance on BAGS Unit 2

Q. Please describe Vectren South's Broadway Avenue Gas Station ("BAGS") Unit 2.

A. BAGS Unit 2 is a simple cycle, 65 MW gas turbine constructed in 1981. The unit will be 44 years old when Vectren South projects retirement in 2025. BAGS Unit 2 will be well past its expected 30-year life. Due to its age, BAGS Unit 2 is not a very efficient unit, operating with a heat rate of over 14,000 in 2017 compared to the proposed new CCGT's anticipated heat rate less than half of this. Recall that a lower heat rate is indicative of greater efficiency.

Q. Are there risks with continuing to operate BAGS Unit 2 for the foreseeable future?

A. Yes. OUCC witness Alvarez's primary criticism is that Vectren South has provided insufficient support for the proposed retirement of BAGS Unit 2 (Public's Exhibit No. 2, p. 14). The data request response he refers to sought "any engineering or other technical reports performed by or on behalf of Vectren South identifying the need to retire the 'Natural Gas' units. The Company is not relying on engineering or other technical reports to support this conclusion. We are planning to retire it 14 years beyond its estimated useful life. As explained in the data request response, Vectren South has trained staff that includes a turbine engineer that supervises the operation and maintenance of the gas peaking units. Our staff has numerous years of experience operating and maintaining natural gas compressor and turbine/generator sets and intimate knowledge of BAGS Unit 2. They have assessed the condition of the unit and found significant risks with continuing to operate it.

Q. Please identify the specific concerns with continued operation of BAGS Unit 2.

A. During normal operation and maintenance activities, long term issues have been found which would require a major re-build of the unit to keep it operating beyond 2025. Our team has identified a damaged turbine casing, the need for exhaust diffuser replacement, replacements of multiple rows of blades and stationary vanes in both the compressor and turbine, a requirement to re-wind the generator stator and rotor, first stage shroud block cracks, leading edge blade damage, and axial movement on the inner guide vanes. Vectren South's modeling appropriately called for the retirement of BAGS Unit 2.

Q. Does Vectren South take seriously its responsibility for keeping assets in good operating condition, operating efficiently, and attaining higher capacity factors?

A. Yes. Vectren South's success in this regard is supported by OUCC witness Alvarez's testimony noting how well our coal plants compare from an operational standpoint to other coal facilities in the nation. (Public's Exhibit No. 2, pp. 16-18). However, operating efficiently may mean determining when to retire units that are well past their useful lives rather than continuing to pour money into the units. Theoretically, Vectren South could ensure that it never retired any generation facilities if that was the goal. But that is not the goal. Throughout his testimony, OUCC witness Alvarez suggests that the only thing that matters in efficiently serving customers is maintaining sufficient capacity, by maintaining existing units, to ensure Vectren South can satisfy its MISO PRM requirements. However, determining the value in pouring money into old inefficient units with short life spans requires a more thorough analysis, including determining whether the existing units are still the most cost effective means of providing service.

Q. OUCC witness Alvarez contends the Company should not have included BAGS 1 in its list of units to be retired. (Public's Exhibit No. 2, p. 13) Why did Vectren South identify BAGS Unit 1 as a unit to be retired?

A. While Mr. Alvarez is correct that BAGS Units 1 has not received any capacity credit from MISO since 2014. Vectren South had classified BAGS Unit 1 in MISO's "temporary suspension" status for the allowable three years period. Prior to 2018, BAGS Unit 1 had not been retired. A temporary suspension status allows a utility time to evaluate the failure of a unit to determine whether investments to bring it back on line are appropriate. BAGS Unit 1 failed in 2015 and the inspection to determine the scope of work and costs to repair the unit concluded that the estimated cost to get the unit operational would be $18 million and that further capital would be required to address several other issues to ensure long term reliability. The unit was 44 years old (same age BAGS 2 will be in 2025 when we are projecting it will retire) and well past its expected life of 30 years. The temporary suspension status provided Vectren South the option to spend the dollars to place the unit back in service prior to mid-2018 if it was determined beneficial. In early 2018, Vectren South submitted the necessary paperwork requesting permission to retire the BAGS Unit 1. The unit was officially retired in early 2018. Therefore, it was appropriate to identify it in the list of resources being retired from Vectren South's fleet.

F. Risks Of Delaying The Decision To Construct a CCGT

Q. Some have suggested that Vectren South should delay the decision to construct a CCGT and wait for the results of the 2019 IRP. Do you agree with this strategy?

A. No. This approach ignores (1) the timing by which Vectren South must make decisions about Brown's continued operation; (2) the timing required to construct a new CCGT and (3) the time required to complete a 2019 IRP and obtain a CPCN. Company witness Retherford explains that environmental regulations will require retirement of the Brown units on or before December 31, 2023 unless significant capital investments are made to have new systems operating well before 2023 as described by Company witness Retherford. When the 2019 IRP modeling is concluded and again recommends construction of a CCGT, there will not be sufficient time to construct the CCGT before Brown must be retired. I have provided a timeline as <u>Petitioner's Exhibit 4-R, Attachment WDG-3R</u> to highlight the challenges. The timeline shows the current projected schedule in green and the timeline under the 2019 IRP in red. Delaying this would push the schedule out 2-3 years (2026/2027 timeframe), leaving customers vulnerable to market capacity and energy prices to reliably serve our customer base during this period. Such an approach would be highly risky and is not a prudent manner in which to operate a utility with an obligation and commitment to industrial, commercial, government, health care, schools and residential customers relying on us to provide reliable electric service.

II. The CCGT Is Reasonable

Q. Several of the intervenors have challenged the size of the proposed unit. Do you agree with their criticisms?

A. No. The primary unit Vectren South is proposing to build does not result in the Company having more capacity than is necessary to serve the projected load over the twenty year planning horizon. The proposed "F" class unit supplies about 700 MWs of baseload generation (prior to making a reduction for summer output and Unforced Capacity ("UCAP") associated with historical forced outage explained in more detail later in my testimony). A unit this size was required to keep costs low, efficiency high and obtain enough capacity to meet Vectren South's PRM with an extra 51 MWs in 2025. This replaces 730 MWs of baseload coal. Petitioner's Exhibit No. 4-R, Attachment WDG-4R, depicts how the baseload capacity matches Vectren South's anticipated needs from the 2016 IRP.

Q. Are there risks that the MISO PRM requirements change or that Vectren South's load increases rendering the additional capacity beneficial?

A. Yes. I discussed in my direct testimony examples of how the MISO PRM requirements have changed in the past and Company witness Joiner explains how the MISO PRM requirement is established and several determining criteria that cause the level to fluctuate annually. I also discussed how holding a capacity surplus is necessary to ensure Vectren South can meet the annual changes in PRM requirements as well as attract new business.

Q. What is the basis for the contention made by the OUCC and ICC that the CCGT has more capacity than necessary for Vectren South to meet its projected needs?

A. Vectren South has proposed to add duct-firing to the CCGT. The duct-firing produces additional steam for the steam generator to increase the amount of electricity it can produce. The incremental cost of adding duct-firing is only $15 million and it produces approximately 150 MWs of additional capacity. The fired portion serves as peaking capacity, allowing Vectren South to supply energy during periods of peak demand and high market prices. Firing the unit cannot be cost-effectively added after the facility is constructed. While constructing the CCGT with duct-firing results in more capacity than our projections indicate is required, the relatively small cost and inability to add it later led us to propose this as part of the CPCN. The 2% increase in cost adds 20% of capacity. This extra capacity can be utilized to help attract new industrial and commercial customers to Evansville or sold into the wholesale market.

Q. Why do you refer to the duct firing as peaking capacity?

A. The air permit will limit the annual tons of Volatile Organic Compounds ("VOCs") being released from the CCGT. The VOCs increase on a per MWHr basis when duct firing which will limit the number of annual hours the unit can be duct fired without exceeding the annual VOC emission limit anticipated in the air permit. Vectren South will monitor VOC emissions and employ the duct firing when MISO demand and energy prices are highest, therefore, only operating during peak times. Vectren South's analysis indicates that VOC emissions limit will not curtail use of the fired piece of the unit, but this limitation supports viewing the duct firing as peaking capacity because it will not be available at all times to serve Vectren South's typical demand.

Q. Does Vectren South have any recommendations if the Indiana Utility Regulatory Commission ("Commission") shares the concern about the need for the capacity resulting from firing the CCGT?

A. Yes. Vectren South witness Chapman has stated that Vectren South is willing to fund the duct-firing portion of the CCGT through shareholder dollars, exclude this piece from future rate base, and accept the risk to recover the investment through wholesale sales energy produced by the duct-firing.

Q. Besides being the lowest cost option for the customer what are some of the other reasons a CCGT is a practical option?

A. The "F" class technology is a highly durable, proven design that has logged numerous operating hours across the power industry. Given the current MISO market and projected market changes discussed by Vectren South witness Joiner, the CCGT has the necessary operating characteristics and flexibility to better react to changing demand and provide the reliable service to our customers. First, the CCGT can ramp output up and down at a rate of 80 MWs per minute providing the flexibility to meet the changing demand requirements created by intermittent resources. This compares to our current coal units that ramp output up and down at a rate of 3 MWs per minute. Second, the unit will be designed with the ability to cycle off and back on nightly if necessary to allow customers to take advantage of low market prices during the off-peak hours when available. The proposed CCGT can start back up from a cold condition in less than an hour, warm condition in 30-40 minutes and hot condition in less than 30 minutes. The

Brown units require 18-24 hours for a cold start, 8-12 hours for a warm start and 4-8 hours for a hot start. The ability to ramp output, cycle on/off quickly and provide reliable capacity as units age are characteristics that have a high probability to create financial benefit in a MISO market that has already moved to a 5 minute pricing settlement period and is exploring market reforms that will reward unit flexibility in the ancillary services market discussed by Company witness Joiner.

The 2x1 "F" class unit consists of 2 sets of compressors, natural gas turbines and generators, heat steam recovery generators (boilers that convert water into steam) and one steam turbine and generator. Simplistically, air is pulled into each of the two compressors where it is compressed to high pressure, is mixed with fuel and ignited. This ignition and combustion moves a hot air fuel mixture through the gas turbine turning blades which drive a shaft within the associated generator producing electricity. The waste heat from each gas turbine enters its associated heat recovery steam generator ("HSRG") where purified water is heated and turned into steam. The high pressure steam enters the turbine. As the steam flows through the turbine blades, the blades turn a shaft connected to the generator. As the generator spins it produces electricity. This design is very efficient as the waste heat from the gas turbines is used to generate more electricity rather than being vented to the atmosphere. The unit has a wide range of output as it can be operated in a 1x1 configuration (one gas turbine/generator, one HRSG and one steam turbine/generator) producing over a range of approximately 180-420 MWs or a 2x1 configuration (two gas turbines/generators, two HRSG's and one steam turbine generator) producing over a range of 380-700 MWs. Duct firing can then be added for peaking. This provides a much wider range of output which is especially beneficial in the off–peak hours when demand and prices are low. Currently the normal minimum output for the Brown units is 135MWs each, Warrick 4 minimum is 114 MWs and Culley 2 minimum is 50 MWs. This means that there are hours during the off-peak when MISO market prices are lower than the cost of our coal units but they can only turn down to 434MWs as compared to the CCGT which can turn down to 180 MWs in the 1x1 configuration and 380MWs in the 2x1 configuration.

Q. Why is the CCGT the lowest cost option?

A. The two primary reasons are the low cost of natural gas and the high efficiency rating of new CCGT technology as compared to Vectren South's coal fleet. The primary measure of efficiency of an electric generation unit is heat rate. Heat rate is the amount of energy in British thermal units ("Btus") used to generate a kilowatt hour ("kWh") of electricity. Heat rate can be expressed in "gross"; the Btu/kWh of total output of the generator (not including electric consumption to operate plant equipment) or "net"; the Btu/kWh (including electrical consumption to operate plant equipment). The lower the heat rate or number of Btu's required to produce a kWh of electricity the more efficient the generating source.

Q. How does the heat rate of the proposed CCGT compare to the coal units that intervenors are recommending Vectren South continue to operate?

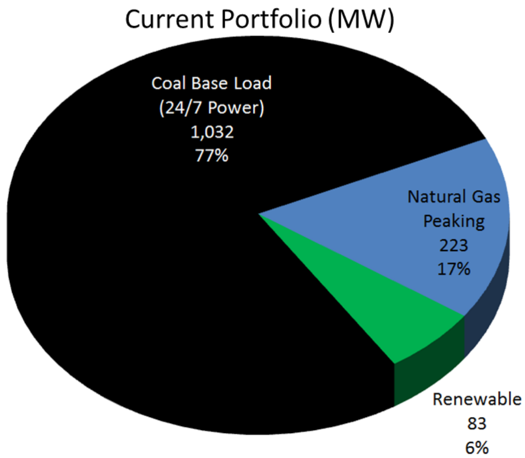
A. The proposed CCGT is expected to operate at an average heat rate of approximately 6,560 Btu/kWh. **Table 7** shows the heat rate of the Vectren South coal fleet.

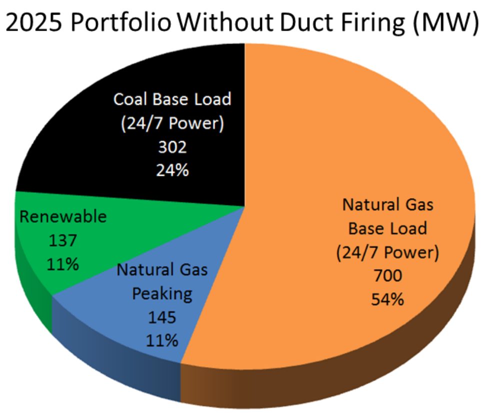
	2017 Net Heat Rate
AB Brown Unit 1	11,576
AB Brown Unit 2	11,007
FB Culley Unit 2	12,662
FB Culley Unit 3	10,549
Warrick Unit 4	10,896
Vectren Coal Fleet Average	11,001
Typical "F" Class CCGT	6,560

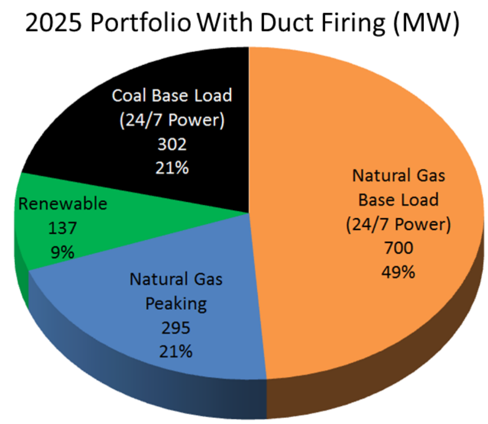
Table 7

Q. OUCC witness Alverez (Public's Exhibit 2, p. 10) claims that Vectren South's preferred plan does not diversify its generation but swings the pendulum from 77% coal to 77% gas. Do you agree with his assessment?

A. No. Fuel diversity can be viewed from the perspective of baseload generation, peaking generation and intermittent generation. As discussed earlier, the Company views duct-firing as peaking generation. As shown in the pie charts below, Vectren South currently has 100% of its baseload capacity supplied by coal. In both the fired and unfired portfolio, this changes to 70% natural gas and 30% coal. When looking at the total portfolio, Vectren South currently has 78% of its total capacity supplied by coal, 16% natural gas peaking and 6% intermittent renewables. In the preferred portfolio with a fired CCGT scenario Vectren South will have 49% baseload gas, 21% baseload coal, 21% peaking gas and 9% intermittent renewables while the unfired portfolio would have 54% baseload gas, 24% baseload coal, 11% peaking gas and 11% intermittent renewables.







Q. Are you concerned that constructing the proposed CCGT is moving to a position of having too much reliance on one unit?

A. No. Although there may be certain advantages to have more than one CCGT, the cost of building the gas pipeline infrastructure, site preparation, engineering, and procurement of equipment construction and interconnect costs of two smaller units outweigh the benefits. The efficiency benefits and cost savings associated with building one larger CCGT is the best option. Building a 2x1 configuration allows Vectren South the flexibility to take one of the gas units off line for planned maintenance in the shoulder months when demand is lowest and operate in a 1x1 configuration producing up to 420 MWs. This energy along with the remainder of Vectren South's fleet will supply enough energy to serve Vectren South shoulder month demand the majority if not all of the time. As mentioned earlier although Vectren South doesn't feel it prudent to rely on the MISO market for energy and capacity for long stretches we should, as MISO members, be able to rely on the market to supply energy in short stretches. If the entire unit is offline for maintenance or to address an operating issue, Vectren South would still have adequate energy with coal and renewables to meet over 40% of its peak demand.

Q. Does Vectren South expect to receive 850 MWs of capacity credit towards its PRM from the CCGT?

A. No. A CCGT's output is dependent on several variables; one being air density. Air density changes with the temperature. During the winter months air density is higher resulting in a CCGT producing more output. Air density in the summer months when temperatures rise to 90 plus degrees is lower resulting in a reduced output. In addition, as discussed by witness Joiner, MISO also penalizes units based on their UCAP performance history. Simplistically, UCAP is based on the demonstrated output of a unit under peak load conditions and percent of time it is not participating in the market due to being forced off-line as a result of operational or maintenance issues. Until the equipment manufacturer is chosen through a competitive bidding process the final summer output will not be known. Each year the UCAP values will change based on previous performance. As a result capacity credit for the unfired and fired portion of the CCGT can be different each year.

III. Cost Estimate Is Reasonable

Q. Did Vectren South develop a detailed cost estimate for the CCGT?

A. Yes. Vectren South witness Diane M. Fischer described in detail the extensive effort the Company invested in developing a very detailed cost estimate for the CCGT. While Ms. Fischer describes the process in great detail, it is important to emphasize that B&V, on behalf of the Company, solicited and evaluated competitive bids for all equipment and construction for the CCGT based on conceptual designs of the CCGT. Ms. Fischer states that the cost estimate represents a +/- 10% estimate for equipment and construction.

Q. Mr. Alvarez criticizes Vectren South's cost estimate (Public's Exhibit No. 2, p. 26) alleging that Company witness Fischer "cannot stand behind [the] estimate without qualifications." Is his criticism valid?

A. No. Vectren South, in conjunction with B&V, has produced a very comprehensive and accurate cost estimate with a plus or minus 10% margin of error. It is still a cost estimate and the actual price may deviate somewhat from this estimate. However, the fact that this is an estimate does not render it unreliable for purposes of Commission consideration. Mr. Alvarez implies that rather than presenting the Commission with a cost estimate, it must provide an unqualified bid to construct the project for a set price. His position ignores that Ind. Code § 8-1-8.5-5(a) requires the submission of a cost estimate, not a firm price.

Q. Mr. Alvarez further criticizes the estimate for not being the result of a competitively bid engineering, procurement or construction contract. Do you agree with him?

A. No. As Mr. Alvarez recognizes, Ind. Code § 8-1-8.5(e)(1)(A) requires the estimated costs of the proposed generation facility of more than 80 megawatts to be "the result of competitively bid engineering, procurement, <u>or</u> construction contracts, as applicable" "to the extent commercially practicable." (Emphasis added) He disregards Vectren South witness Fischer's testimony that Vectren South's cost estimate is the result of competitively bid procurement and construction contracts. <u>Petitioner's Exhibit No. 6</u>, pp. 36-37. Mr. Alvarez may be ignoring the use of the conjunctive "or" in the statute and misreading the statute as requiring presentation of an engineering, procurement <u>and</u> construction or EPC contract. In an EPC contract, the contractor is responsible for obtaining all specified equipment, designing the plant, constructing the plant and assuming the project cost. The statute does not require an EPC contract as evidenced by the language providing the option of competitively bid engineering, procurement <u>or</u> construction contracts.

Q. Would it be commercially practicable for Vectren South to obtain an EPC contract bid and present it to the Commission in conjunction with a CPCN request?

A. No. A contractor offering a bid on a contract incurs significant expense in developing these bids. Costs can range from $300,000 to $1 million for the bid preparation. An EPC contract often includes a firm price, which requires the contractor to be very thorough in providing a bid. Contractors will not put the investment into developing firm bids simply for Vectren South to submit them to the Commission for approval in a CPCN proceeding. The length of time required for approval of a CPCN also makes it commercially impracticable to obtain a firm EPC contract bid as conditions change over time (supply & demand impacting commodity prices, labor market availability, *etc*.) resulting in high contingency being included in the firm bids to ensure adequate profit margins. In addition waiting for a CPCN places Vectren South in a much better position to create a competitive market and negotiate terms as bidders will be much more serious once they know there is an actual project they are investing the time and effort to earn.

Q. Do you agree with Mr. Alvarez that there are "red flags" in the proposed cost estimate that signal price escalation, construction-scheduling uncertainty, and lack of general confidence in its ability to undertake projects of this magnitude (Public's Exhibit No. 2, p. 28)?

A. No. Vectren South employed B&V to develop this +/-10% cost estimate as they have extensive experience as an EPC contractor and an Owners Engineer involved in several CCGT projects. They used the same cost estimating practices and review they use when bidding a project as an EPC. The typical costs for an "F" class combined cycle gas turbine project are well known as there are over 258,000MWs of combined cycle output in the United States. This is in contrast to the Edwardsport and Mississippi Powers Integrated Gasification Combined Cycle ("IGCC") technology that Industrial Group witness Michael Gorman unfairly points to as examples of over budget and over schedule projects. These were first of a kind technology projects that were not proven. Vectren South originally partnered with Duke on Edwardsport but bowed out before the project started largely because of the difficulties confirming the prices.

The OUCC's "red flags" comment ignores the entire body of work performed by Vectren to put together a very detailed estimate for the Commission. Vectren South and B&V performed a significant level of conceptual design to develop the estimate for the CCGT. This includes development of site arrangement drawings, a full set of flow diagrams, a detailed bill of quantities, a detailed project execution plan and construction plan, a level one schedule, one line diagrams and project sequencing plans to ensure that the estimate was suitable for the Company's use in obtaining approval from the Commission. In addition, as stated in Ms. Fischer's testimony, the estimate "represents a +/- 10% estimate for equipment and a +/- 10% estimate for construction."

B&V followed the same procedures and practices for developing the project cost as would be used for projects where they are the EPC Contractor. This same estimating template was used for the following B&V EPC projects listed in **Table 8** (provided by B&V). These examples demonstrate that B&V has the experience with several CCGT projects that have been completed on schedule and on budget, further supporting the reasonableness of these cost estimates.

Project Name	CT Model	Configuration	% Complete	On Budget	On Schedule
Tenaska Westmoreland	Mitsubishi M501J	2x1 CCPP	90%	Y	Y
Oregon Clean Energy	Siemens SGT6-	2x1 CCPP	100%	Y	Y
Enmax Shepard	MHI M501G	2x1 CCPP	100%	Y	Y
FPL Ft. Myers	GE 7FA.05	2x0 SCPP	100%	Y	Y
FPL Lauderdale	GE 7FA.05	5x0 SCPP	100%	Y	Y
Westar Emporia	GE 7FA & LM6000	7x0 SCPP	100%	Y	Y

Table 8

Q. Did Vectren South omit the costs for the lateral pipeline to serve the proposed CCGT from its cost estimate as Mr. Alvarez alleges (Public's Exhibit No. 2, p. 27)?

A. No. It was included as fixed O&M costs, as was indicated in response to discovery.

IV. Recommendations For CCGT Cost Exposures

Q. Industrial Group witness Gorman makes several recommendations for contractual protections when negotiating an EPC for the CCGT. Will Vectren South consider these recommendations?

A. Yes. Mr. Gorman recommends that Vectren South include appropriate contractual provisions that shift the risk of cost overruns on the CCGT to the Company's major equipment suppliers or the EPC contractor. He also recommends performance obligations in its supply contracts to ensure that a new CCGT can meet these expected operating performances.

Q. Has Vectren South decided what method it will utilize to contract for the engineering, procurement and construction of the CCGT?

A. No. Vectren South leans towards and desires a fixed price EPC contract with payments made as specific quality, productivity and performance milestones are achieved. This approach would shift many of the risks of cost overruns to the EPC contractor. We will hire an Owners Engineer with EPC experience to help guide us through the best way to structure the EPC contract to ensure the project is completed on schedule and within budget. Knowing that EPC contractors will add a premium for taking on the risk associated with a firm price Vectren South will evaluate whether the benefits of a fixed price bid are justified by its costs. Even with a firm price, there are risks of change orders and unanticipated issues that can impact the price.

Q. Has Vectren South decided whether it will require performance obligations in any agreement with an EPC contractor?

A. Yes. Specific performance obligations associated with project milestones will be established. Cost sharing incentives for completing specific phases of work under established budgets is something that has worked well for Vectren South on previous capital projects and will be something we'll explore for this project.

Q. Mr. Gorman also recommends that Vectren South share all of the wholesale power margins generated by the plant with customers. Has Vectren South considered this recommendation?

A. Yes. The parties are correct that a significant benefit of the new CCGT is the enhanced ability to participate in the MISO energy market because of the unit's greater efficiency. Vectren South witness Chapman has agreed that in the Company's next base rate case, it will agree to modify its wholesale power sharing mechanism to adjust the portion of wholesale sales shared with customers from 50% to 100%. As Company witness Lind explains, this will further improve the benefits to customers from the CCGT.

V. Alternative FGD Options Were Explored

Q. Please describe the process Vectren South engaged in to explore scrubber options for Brown.

A. Vectren South hired B&McD to assess the condition of the Brown Scrubber, the estimated remaining life and estimated replacement cost. B&McD associates visited the Brown plant to view and assess the condition, examine historical maintenance documents, become familiar with other environmental controls and how they interact and understand the characteristics of the coal burned.

Q. Why did Vectren South focus on the wet limestone FGD?

A. Based on its investigation, B&McD considered options and concluded that Wet Limestone Forced Oxidation ("LSFO") was the best option for the Brown plant. They based this decision on size of the Brown units and the long track record of high SO_2 removal rates and high operating reliability on high sulfur coal applications. B&McD did consider other technologies, contrary to OUCC witness Aguilar's assertion that no other technologies were evaluated (Public's Exhibit No. 1, p. 20). These were ruled out by B&McD due to their lack of a track record of performance on high sulfur coal, higher long term O&M costs, addition of new environmental equipment such as a fabric filter downstream of the process, concerns with impact to fly ash quality and interaction with other plant environmental controls. Solid performance with high sulfur coal is critical as there is always the possibility for lowering SO_2 removal requirements and emission allowances.

Q. Is the Company presenting additional evidence to demonstrate that other scrubber technologies are not viable?

A. Yes. Vectren South witness Farber has evaluated the scrubbers the OUCC and ICC claim should have been further reviewed and explains why those options are either economically or operationally problematic.

VI. Conclusion

Q. Does this conclude your prepared rebuttal testimony?

A. Yes, at this time.

VERIFICATION

The undersigned, Wayne D. Games, affirms under the penalties of perjury that the answers in the foregoing Rebuttal Testimony in Cause No. 45052 are true to the best of his knowledge, information and belief.

Wayne D. Games

Wayne D. Games

Corrosion Projects 2008-2018

	Grand Total Spend	**$**	**32,081,501**
	Avg Yearly Spend	**$**	**2,916,500**

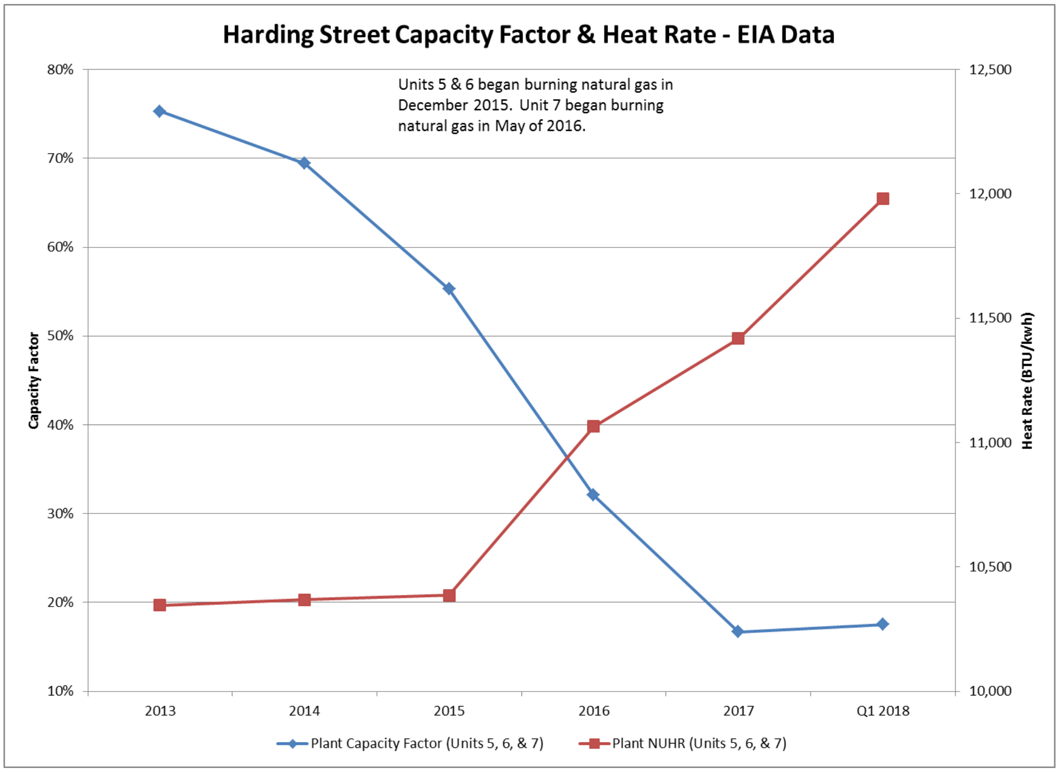
Projects by Year

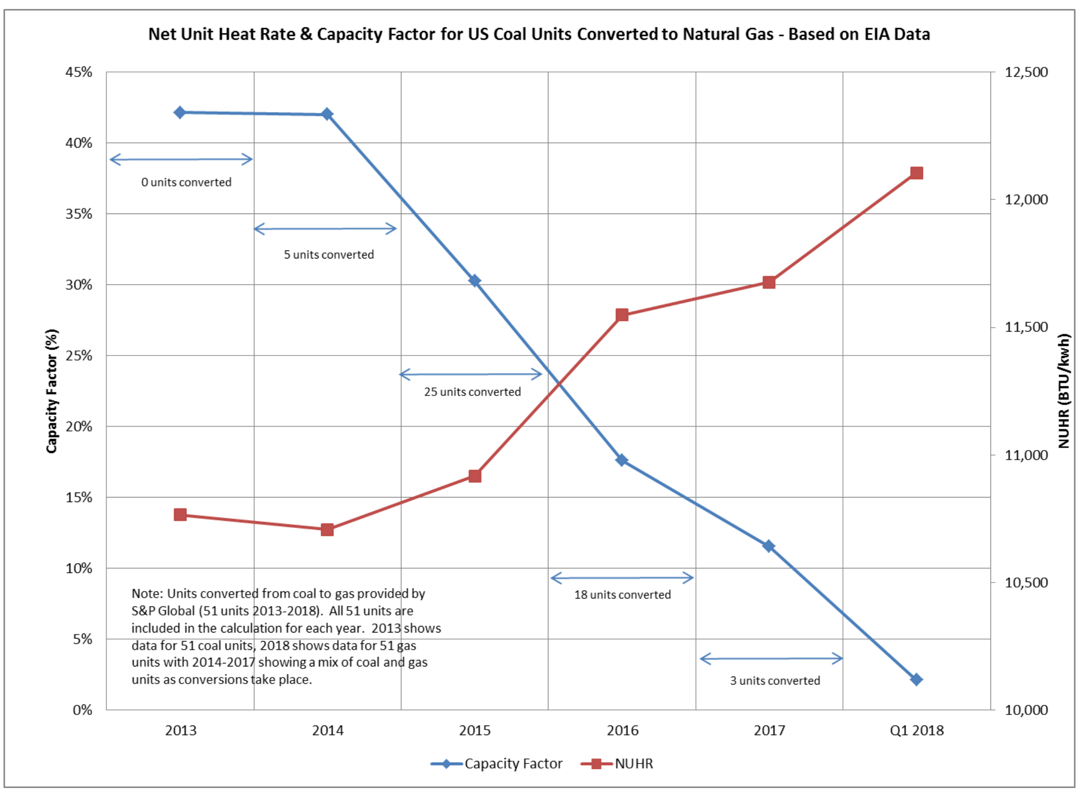
	2018		**Cost**
1	U1 North/South Tower Phase 2	$	886,000
2	U1 - U2 Walk Way	$	350,000
3	U2 Inlet Duct Platforms	$	150,000
	Total	**$**	**1,386,000**
	2017		
1	U2 Coal Silo Replacement/Repair	$	1,000,000
2	U1 North/South Absorber Duct Tower Replacement	$	1,800,000
3	U1 North/South Absorber Duct Tower Replacement Phase 2-4	$	400,000
	Total	**$**	**3,200,000**
	2016		
1	U1 Coal Silo Vertical Wall, Cone Weld Replacement	$	2,900,000
2	U1 Belt Filter Replacement	$	1,300,000
3	U1 Truck Chute Replacement	$	200,000
4	U2 North/ South Tower Absorber Duct Support Tower Phase I	$	250,000
5	U2 Coal Silo Cone Repairs	$	175,000
6	U2 Coal Silo Vertical Wall Assessment	$	25,000
7	U1 Belt Filter Temporary reenforcement	$	10,000
8	U2 Cooling Tower Cell D,E,F &G Structure and Face replacement	$	480,000
9	Coal Yard Hoppers (5)	$	650,000
10	U1/U2 FGD Corrosion Study	$	40,000
11	Ranney Well Floor Sturcture	$	30,000
	Total	**$**	**6,060,000**
	2015		
1	U2 North Belt Filter reenforcement	$	10,000
2	U2 FGD Chute replacement	$	200,000
3	U1 Stack (32) Lower stack band replacement	$	300,000
4	U1 Stack Fan replacement (2)	$	100,000
6	FGD Lime Silo Roof Replacement	$	800,000
7	U2 FGD Building / Floor Structure/ Drains	$	300,000
8	U1 FGD Building Structural/ Columns	$	250,000
9	Coal Hopper (1)	$	200,000
10	U2 FGD Building South Wall Replacement	$	150,000
11	U1 Lime Mixing Tank Stair Tower	$	78,000
	Total	**$**	**2,388,000**
	2014		
1	U2 FGD Thickener Tank Bridge Structure repairs and coating	$	275,000
2	U1 FGD Building Structure and Walls - South and East	$	300,000
3	Carboline Facility Coating Assesment		NA
4	U2 CT Cell Replacement A, B & C	$	3,400,000
5	U2 Lime Mixing Tank Emergency Repairs and Shoring	$	30,000
	Total	**$**	**4,005,000**

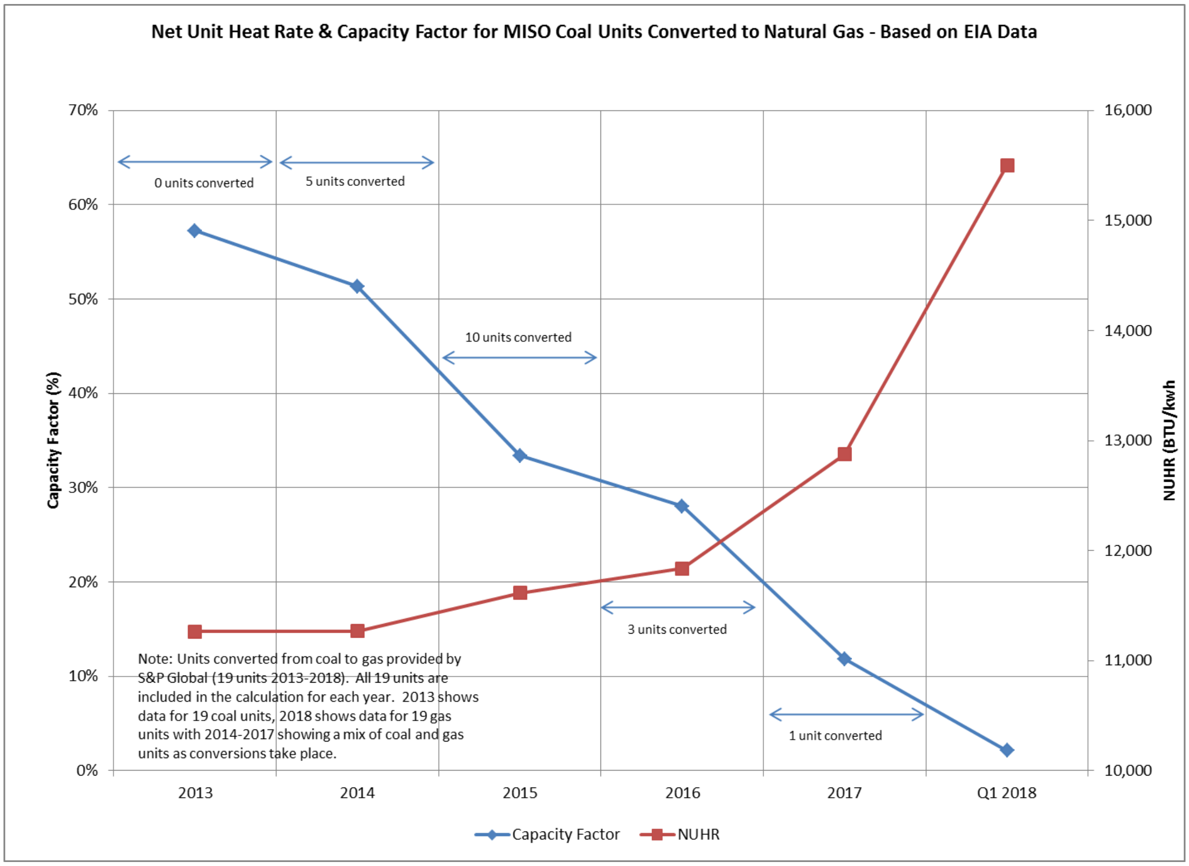
	2013		
1	U2 South Belt Filter Structure Replacement	$	600,000
2	Coal Conveyor C Truss Connecting plate seal and and coating	$	150,000
3	Train Trestle Rebuild	$	2,300,000
4	U2 Absorber Tower Coating	$	800,000
5	U1 Lime Mixing Tank Replacement	$	750,000
6	U1 FGD Pump Room Structure/ Siding and foundation replacement	$	400,000
	Total	**$**	**5,000,000**
	2012		
1	U1 FGD Building Structure and Walls - North and West	$	200,000
2	U1 Cooling Tower Replacement Cells A-G	$	5,950,000
3	U1 Absorber Tower Coating	$	800,000
	Total	**$**	**6,950,000**
	2011		
1	U2 FGD Building Structural Steel and Siding Replacement	$	1,100,000
	Total	**$**	**1,100,000**
	2010		
1	Repair of handrails, ladders, and platform grating on Unit 2 precipitator	$	135,401
2	U1 Outage Cleaning and Patching Holes on Thickener Tank	$	115,851
3	U2 SCR MCC cable enclosure rusted	$	66,767
4	U1 FGD MCC Bldg	$	51,628
	Total	**$**	**369,647**
	2009		
1	PHASE 3 ABB2 FGD (2009) corrosion repair U2	$	395,063
2	3I Eng Study	$	108,170
3	PHASE 3 ABB1 FGD (2009) corrosion repair U1	$	100,264
4	3I Engineering Study	$	93,270
5	Top Edge SE side - Thickner Tank	$	83,299
6	3I Engineering to perform a structural analysis of the FGD area	$	72,784
7	3I Engineering to perform a structural analysis of FGD area	$	63,769
	Total	**$**	**916,619**
	2008		
1	Phase 2 Corrosion repairs - 3I Eng , structural repairs U2 scrubber	$	315,184
2	Phase 2 Corrosion repairs - 3I Eng , structural repairs U1 scrubber	$	211,511
3	UNIT 1 FGD PLATFORM AND HANDRAIL SYSTEM CORROSION REPAIRS	$	179,541
	Total	**$**	**706,236**

Petitioner's Exhibit No. 4-R, Attachment WDG-2R

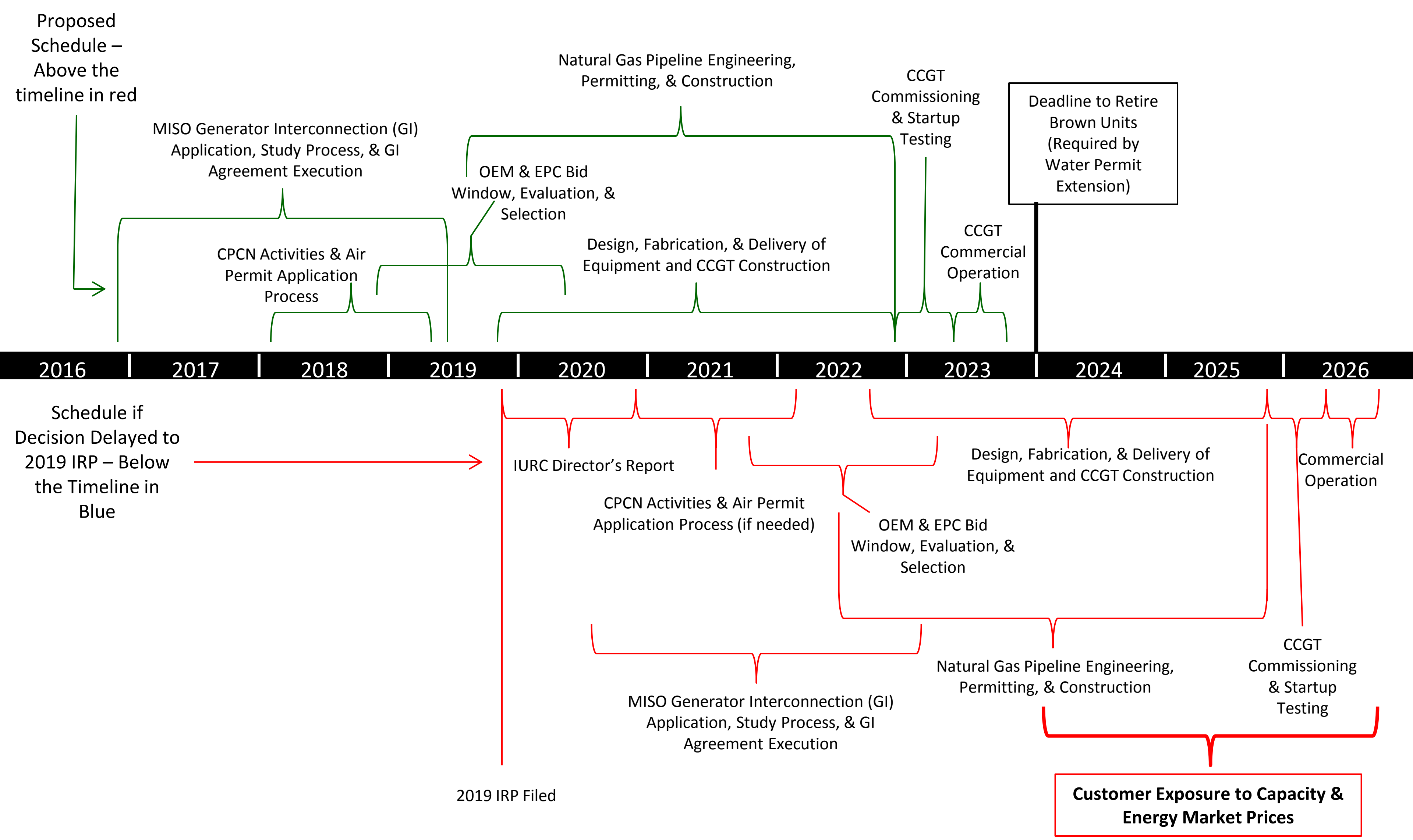
Cause No. 45052

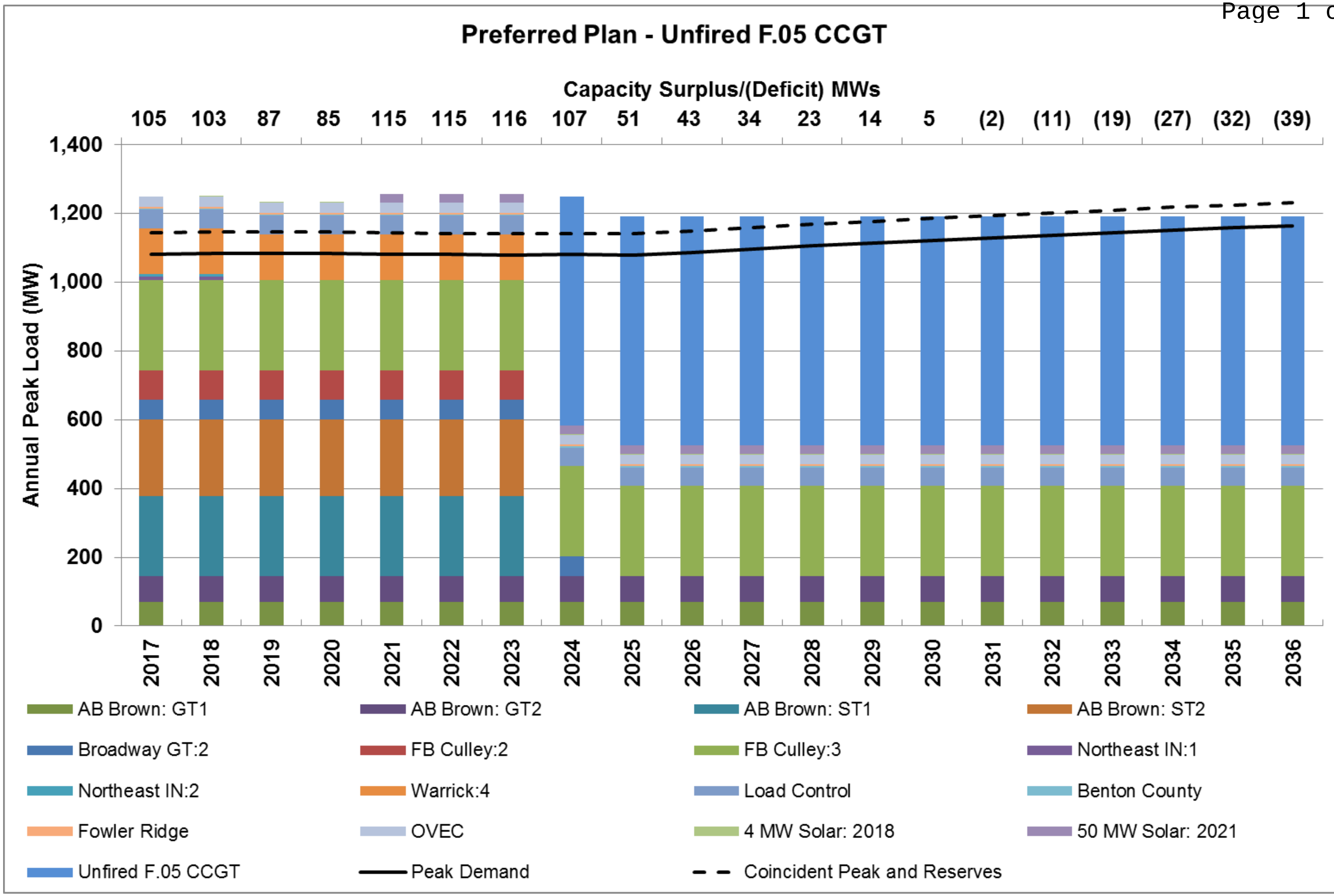





Net Unit Heat Rate & Capacity Factor for MISO Coal Units Converted to Natural Gas - Based on EIA Data
Capacity Factor (%)
NUHR (BTU/kwh)
0 units converted
5 units converted
10 units converted
3 units converted
1 unit converted
Note: Units converted from coal to gas provided by S&P Global (19 units 2013-2018). All 19 units are included in the calculation for each year. 2013 shows data for 19 coal units, 2018 shows data for 19 gas units with 2014-2017 showing a mix of coal and gas units as conversions take place.
70%
60%
50%
40%
30%
20%
10%
0%
16,000
15,000
14,000
13,000
12,000
11,000
10,000
2013
2014
2015
2016
2017
Q1 2018
Capacity Factor
NUHR

CCGT Timeline of Activities




Preferred Plan - Unfired F.05 CCGT
Capacity Surplus/(Deficit) MWs
105 103 87 85 115 115 116 107 51 43 34 23 14 5 (2) (11) (19) (27) (32) (39)
Annual Peak Load (MW)
1,400
1,200
1,000
800
600
400
200
0
2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036
AB Brown: GT1
AB Brown: GT2
AB Brown: ST1
AB Brown: ST2
Broadway GT:2
FB Culley:2
FB Culley:3
Northeast IN:1
Northeast IN:2
Warrick:4
Load Control
Benton County
Fowler Ridge
OVEC
4 MW Solar: 2018
50 MW Solar: 2021
Unfired F.05 CCGT
Peak Demand
Coincident Peak and Reserves

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 154
EPA COBRA Schahfer Retirement Analysis

An official website of the United States government.

COBRA Web Edition

CO-Benefits Risk Assessment (COBRA) is a screening tool that enables state, local, and tribal government staff and others interested in the effects of air pollution to estimate the air quality and health benefits of different emissions scenarios.

You are using the web-based version of COBRA. For the COBRA desktop application, visit the COBRA download page.

Step 1: Build Scenario

Complete the sections below and click "Add to Scenario."

A. Select Location REQUIRED

Select the states or counties where the emissions changes will occur.

- [ ] Jefferson
- [ ] Jennings
- [ ] Johnson
- [ ] Knox
- [ ] Kosciusko
- [ ] Lagrange
- [ ] Lake
- [ ] La Porte
- [ ] Lawrence
- [ ] Madison

Select All | Deselect All

B. Select Sector REQUIRED

Select the industry or sector where the emissions changes will occur.

Sector

Fuel Combustion: Industrial

Subsector (optional)

All subsectors

Subsector (optional)

All subsectors

C. Modify Emissions REQUIRED

Enter emissions changes for **at least one** of the four pollutants below.

$PM_{2.5}$ (Baseline = 1,409.26 tons)

reduce by **increase by**

enter # tons percent

SO_2 (Baseline = 12,302.81 tons)

reduce by **increase by**

enter # tons percent

NO_x (Baseline = 7,839.23 tons)

reduce by **increase by**

enter # tons percent

VOC (Baseline = 115.38 tons)

reduce by **increase by**

enter # tons percent

NH_3 (Baseline = 35.93 tons)

reduce by **increase by**

enter # tons percent

ADD TO SCENARIO

Step 2: Review Scenario

Review the scenario below. To add changes to more locations or sectors, repeat Step 1 to continue building your scenario.

Location(s)	Sector	Emissions Modification(s)	
Jasper, Indiana Porter, Indiana	Fuel Combustion: Industrial	$PM_{2.5}$ reduce by 70 tons SO_2 reduce by 395.04 tons NO_x reduce by 1,351.4 tons	✕

Discount rate:

2%

Custom: enter %

RUN SCENARIO

Step 3: View Results

BUILD NEW SCENARIO

A. Summary of Health Effects Results

Below is a table with the health effects results based on your scenario.

You are viewing results for all contiguous U.S. states. This is because changes in air quality can impact health endpoints in multiple locations due to the transportation of emissions across state and county lines.

Use the filters below to see health effects for a specific state or county.

1. Filter by state:

All contiguous U.S. states

2. Filter by county: (optional)

All counties

Results for: All Contiguous U.S. States

Export: All results | Current filter

Health Endpoint	Pollutant	Change in Incidence (cases, annual)		Monetary Value (dollars, annual)	
		Low	High	Low	High
Mortality *	$PM_{2.5}$ | O_3	9.4	16	$140,000,000	$230,000,000
Nonfatal Heart Attacks	$PM_{2.5}$	3.8	3.8	$320,000	$320,000
Infant Mortality	$PM_{2.5}$	0.049	0.049	$760,000	$760,000
Hospital Admits, All Respiratory	$PM_{2.5}$ | O_3	1	1	$24,000	$24,000
Emergency Room Visits, Respiratory	$PM_{2.5}$ | O_3	12	12	$19,000	$19,000
Asthma Onset	$PM_{2.5}$ | O_3	39	39	$3,000,000	$3,000,000
Asthma Symptoms	$PM_{2.5}$ | O_3	6,400	6,400	$1,500,000	$1,500,000
Emergency Room Visits, Asthma	O_3	0.048	0.048	$40	$40
Lung Cancer Incidence	$PM_{2.5}$	0.38	0.38	$17,000	$17,000
Hospital Admits, Cardio-Cerebro/Peripheral Vascular Disease	$PM_{2.5}$	0.77	0.77	$22,000	$22,000
Hospital Admits, Alzheimers Disease	$PM_{2.5}$	2.7	2.7	$61,000	$61,000

Hospital Admits, Parkinsons Disease	$PM_{2.5}$	0.37	0.37	$8,900	$8,900
Stroke Incidence	$PM_{2.5}$	0.33	0.33	$21,000	$21,000
Hay Fever/Rhinitis Incidence	$PM_{2.5}$ | O_3	250	250	$280,000	$280,000
Cardiac Arrest, Out of Hospital	$PM_{2.5}$	0.078	0.078	$4,800	$4,800
Emergency Room Visits, All Cardiac	$PM_{2.5}$	1.7	1.7	$3,600	$3,600
Minor Restricted Activity Days	$PM_{2.5}$	4,100	4,100	$520,000	$520,000
School Loss Days	O_3	2,400	2,400	$4,000,000	$4,000,000
Work Loss Days	$PM_{2.5}$	690	690	$220,000	$220,000
Total Health Effects from $PM_{2.5}$				**$83,000,000**	**$180,000,000**
Total Health Effects from O_3				**$65,000,000**	**$65,000,000**
Total Health Effects				**$150,000,000**	**$240,000,000**

Note: Dollar amounts shown are based on 2023 currency values. Additionally, all values have been rounded to 2 significant figures. Please export the results in order to see values prior to rounding.

* The Low and High values represent differences in the methods used to estimate some of the health impacts in COBRA. For example, high and low results for avoided premature mortality are based on two different epidemiological studies of the impacts of $PM_{2.5}$ on mortality in the United States.

B. Map of Health Effects and Air Quality Results

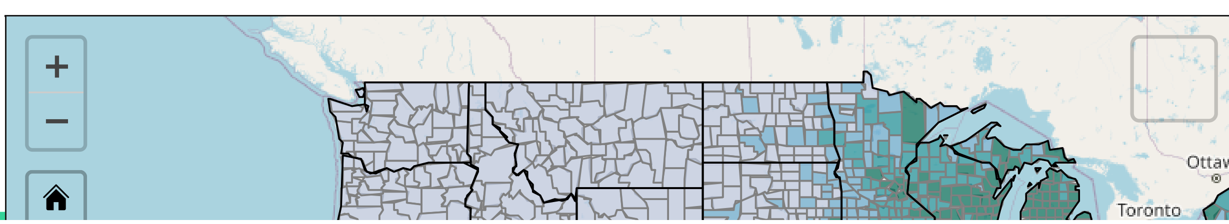
Below is a map showing health effects and air quality data based on your scenario.

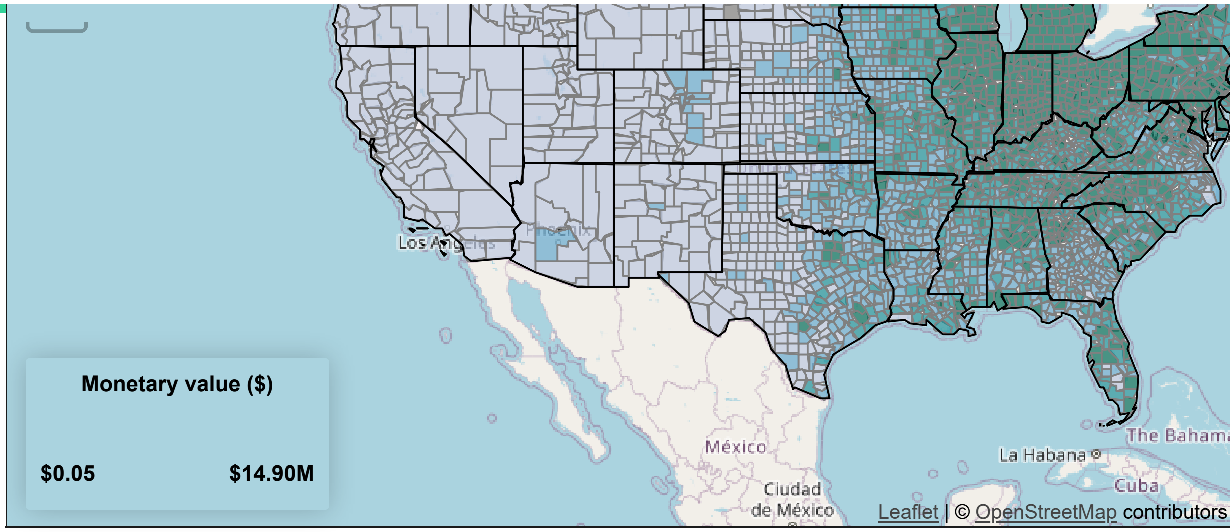
Use the filter below to change the map's data layer. Click on a county on the map to explore the data.

Select the map's data layer:

Total Health Benefits ($, low estimate)

Displaying: Total Health Benefits ($, low estimate)





LAST UPDATED ON APRIL 12, 2021

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 155
EPA COBRA Culley Retirement Analysis

An official website of the United States government.

COBRA Web Edition

CO-Benefits Risk Assessment (COBRA) is a screening tool that enables state, local, and tribal government staff and others interested in the effects of air pollution to estimate the air quality and health benefits of different emissions scenarios.

You are using the web-based version of COBRA. For the COBRA desktop application, visit the COBRA download page.

Step 1: Build Scenario

Complete the sections below and click "Add to Scenario."

A. Select Location REQUIRED

Select the states or counties where the emissions changes will occur.

- [ ] Warren
- [x] Warrick
- [ ] Washington
- [ ] Wayne
- [ ] Wells
- [ ] White
- [ ] Whitley

- [ ] Iowa
- [ ] Kansas

Select All | Deselect All

B. Select Sector REQUIRED

Select the industry or sector where the emissions changes will occur.

Sector

Fuel Combustion: Electric Utility

Subsector (optional)

All subsectors

Subsector (optional)

All subsectors

C. Modify Emissions REQUIRED

Enter emissions changes for **at least one** of the four pollutants below.

$PM_{2.5}$ (Baseline = 2,770.88 tons)

reduce by | **increase by**

enter # tons percent

SO_2 (Baseline = 6,509.96 tons)

reduce by | **increase by**

enter # tons percent

NO_x (Baseline = 9,745.69 tons)

reduce by | **increase by**

enter # tons percent

VOC (Baseline = 282.18 tons)

reduce by | **increase by**

enter # tons percent

NH_3 (Baseline = 1.11 tons)

reduce by | **increase by**

enter # tons percent

ADD TO SCENARIO

Step 2: Review Scenario

Review the scenario below. To add changes to more locations or sectors, repeat Step 1 to continue building your scenario.

Location(s)	Sector	Emissions Modification(s)	
Warrick, Indiana	Fuel Combustion: Electric Utility Coal	$PM_{2.5}$ reduce by 9.2 tons SO_2 reduce by 247.83 tons NO_x reduce by 320.79 tons	✕

Discount rate:

2%

Custom: enter %

RUN SCENARIO

Step 3: View Results

BUILD NEW SCENARIO

A. Summary of Health Effects Results

Below is a table with the health effects results based on your scenario.

You are viewing results for all contiguous U.S. states. This is because changes in air quality can impact health endpoints in multiple locations due to the transportation of emissions across state and county lines.

Use the filters below to see health effects for a specific state or county.

1. Filter by state:

All contiguous U.S. states

2. Filter by county: (optional)

All counties

Results for: All Contiguous U.S. States

Export: All results | Current filter

Health Endpoint	Pollutant	Change in Incidence (cases, annual)		Monetary Value (dollars, annual)	
		Low	High	Low	High
Mortality *	$PM_{2.5}$ | O_3	2.5	3.9	$36,000,000	$58,000,000
Nonfatal Heart Attacks	$PM_{2.5}$	0.92	0.92	$78,000	$78,000
Infant Mortality	$PM_{2.5}$	0.011	0.011	$170,000	$170,000
Hospital Admits, All Respiratory	$PM_{2.5}$ | O_3	0.28	0.28	$6,400	$6,400
Emergency Room Visits, Respiratory	$PM_{2.5}$ | O_3	3.3	3.3	$5,300	$5,300
Asthma Onset	$PM_{2.5}$ | O_3	10	10	$790,000	$790,000
Asthma Symptoms	$PM_{2.5}$ | O_3	1,700	1,700	$430,000	$430,000
Emergency Room Visits, Asthma	O_3	0.014	0.014	$12	$12
Lung Cancer Incidence	$PM_{2.5}$	0.083	0.083	$3,700	$3,700
Hospital Admits, Cardio-Cerebro/Peripheral Vascular Disease	$PM_{2.5}$	0.17	0.17	$4,900	$4,900
Hospital Admits, Alzheimers Disease	$PM_{2.5}$	0.67	0.67	$15,000	$15,000

Hospital Admits, Parkinsons Disease	$PM_{2.5}$	0.078	0.078	$1,900	$1,900
Stroke Incidence	$PM_{2.5}$	0.072	0.072	$4,500	$4,500
Hay Fever/Rhinitis Incidence	$PM_{2.5}$ | O_3	66	66	$74,000	$74,000
Cardiac Arrest, Out of Hospital	$PM_{2.5}$	0.017	0.017	$1,000	$1,000
Emergency Room Visits, All Cardiac	$PM_{2.5}$	0.38	0.38	$820	$820
Minor Restricted Activity Days	$PM_{2.5}$	890	890	$110,000	$110,000
School Loss Days	O_3	690	690	$1,200,000	$1,200,000
Work Loss Days	$PM_{2.5}$	150	150	$47,000	$47,000
Total Health Effects from $PM_{2.5}$				**$19,000,000**	**$40,000,000**
Total Health Effects from O_3				**$20,000,000**	**$20,000,000**
Total Health Effects				**$39,000,000**	**$60,000,000**

Note: Dollar amounts shown are based on 2023 currency values. Additionally, all values have been rounded to 2 significant figures. Please export the results in order to see values prior to rounding.

* The Low and High values represent differences in the methods used to estimate some of the health impacts in COBRA. For example, high and low results for avoided premature mortality are based on two different epidemiological studies of the impacts of $PM_{2.5}$ on mortality in the United States.

B. Map of Health Effects and Air Quality Results

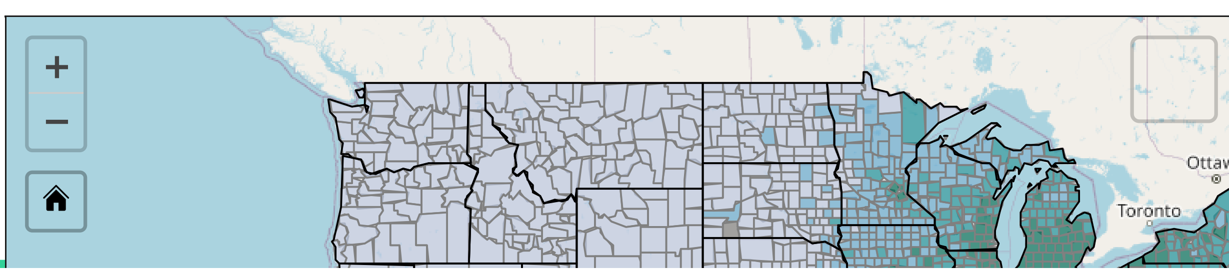
Below is a map showing health effects and air quality data based on your scenario.

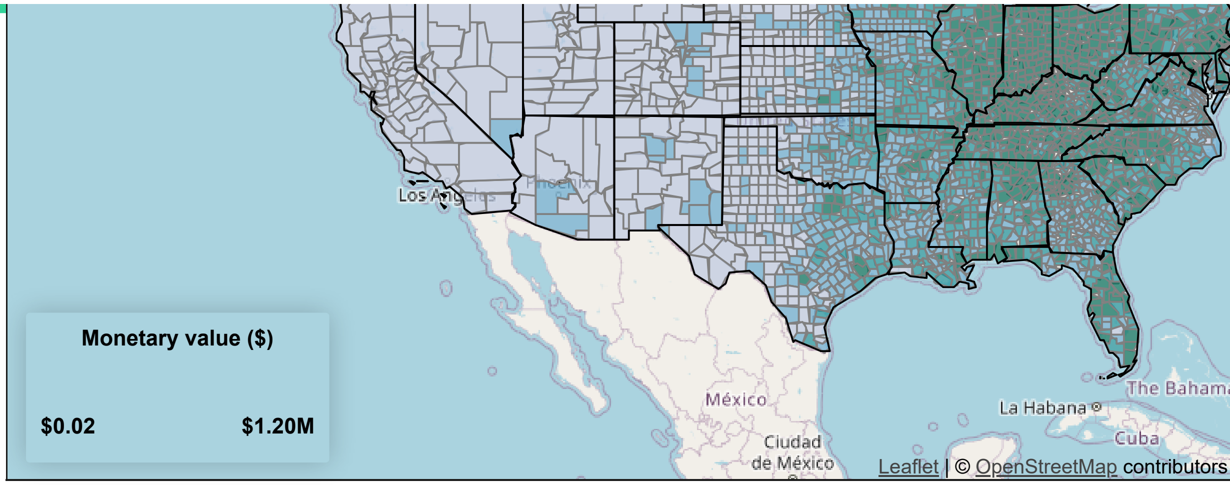
Use the filter below to change the map's data layer. Click on a county on the map to explore the data.

Select the map's data layer:

Total Health Benefits ($, low estimate)

Displaying: Total Health Benefits ($, low estimate)





LAST UPDATED ON APRIL 12, 2021

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 156
CenterPoint Cost Allocation Complaint

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Southern Indiana Gas and Electric Company	)	
	)	Docket No. EL26-___-000
v.	)	
	)	
Midcontinent Independent System Operator, Inc.	)	

COMPLAINT REQUESTING FAST TRACK PROCESSING

Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South ("SIGE" or "Company") files this complaint ("Complaint") and request for Fast Track processing against Midcontinent Independent System Operator, Inc. ("MISO"), pursuant to sections 202(c), 306, and 309 of the Federal Power Act ("FPA"),[1] and Rule 206 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("FERC" or "Commission").[2] SIGE is the operating utility subsidiary of CenterPoint Energy, Inc. ("CenterPoint") and owns and operates Unit 2 of the F.B. Culley Generating Station, the subject of a recent Department of Energy ("DOE") order under FPA Section 202(c).[3]

On December 23, 2025, the U.S. Secretary of Energy issued an order pursuant to FPA section 202(c) and section 301(b) of the Department of Energy Organization Act ("DOE Organization Act")[4] declaring 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

---

1 16 U.S.C. §§ 824a(c), 825e, 825h.

2 18 C.F.R. § 385.206 (2025).

3 16 U.S.C. § 824a(c). F.B. Culley Generating Station ("Culley Plant") is an electric generating facility in Warrick County, Indiana. Culley Plant is owned and operated by SIGE and consists of two coal-fired generation units, Unit 2 ("Culley Unit 2") and Unit 3 ("Culley Unit 3"), with a combined name plate capacity of 368.9 MW. Culley Unit 2 is the focus of the recent DOE Order, which CenterPoint's operating subsidiary, SIGE, owns and is responsible for operating.

4 42 U.S.C. § 7151(b).

electric energy, and other causes."[5] On that basis, the DOE Order directs both the Company and MISO to "take all measures necessary to ensure" that Culley Unit 2, which had been scheduled to cease operations on December 31, 2025, continues to operate.[6] SIGE has complied with its obligations under the DOE Order since it was issued, and Culley Unit 2—while currently in a maintenance outage—is being prepared to be offered into the MISO market and to produce energy when dispatched.

The DOE Order makes clear that "[r]ate recovery is available pursuant to [FPA section 202(c)]," and further directs the Company to "file with the Federal Energy Regulatory Commission Tariff revisions or waivers to effectuate this order."[7] This Complaint is being filed in furtherance of that directive and to ensure that there is a mechanism for SIGE to obtain such rate recovery as is available pursuant to FPA section 202(c) at the appropriate time in the future, likely after the DOE Order expires.[8]

To be clear, ***the specific costs, if any, to be recovered by the Company are not at issue in this Complaint.*** Rather, as in the Consumers Energy complaint proceeding, the Company plans

[5] U.S. Department of Energy, Order No. 202-25-13, at 1 (Dec. 23, 2025) (DOE Order) https://www.energy.gov/documents/order-number-202-25-13-culley.

[6] *Id.* at 5.

[7] *Id.* at Ordering Paragraph E.

[8] This Complaint follows a similar complaint filed by Consumers Energy Company after that company was required by the DOE, pursuant to FPA section 202(c), to continue operating a generation facility in MISO. In Docket No. EL25-90-000, Consumers Energy filed a complaint requesting that the Commission order MISO to revise its Tariff to adopt a mechanism to allow the company to recover its costs of compliance with the relevant 202(c) order and to allocate such costs to load serving entities in MISO Zones 1 through 7. The Commission granted the Consumers Energy complaint and recently denied rehearing. *Consumers Energy Co. v. Midcontinent Indep. Sys. Operator, Inc.*, 192 FERC ¶ 61,158 (Consumers Complaint Order); *order on reh'g*, 193 FERC ¶ 61,228 (2025) (Consumers Rehearing Order). In the Consumers Complaint Order, the Commission directed MISO to make a compliance filing to adopt the cost recovery schedule proposed by Consumers Energy, with slight modifications. *See* MISO, Compliance to Consumers Energy Company Complaint, Docket No. ER25-3425-000 (filed Sept. 15, 2025) (pending).

to make a separate section 202(c) cost recovery filing at some point after the expiration of the DOE Order (which currently covers the time period through March 23, 2026).[9] In that separate, future filing, SIGE will present, explain, and support what it believes are its just and reasonable costs associated with running Culley Unit 2 from the date of the DOE Order through March 23, 2026, or as such time may be extended by subsequent order of the Secretary, netting out applicable market revenues ("Order Costs").[10] Thus, the determination of recoverable costs will be the subject of a separate FERC proceeding under section 202(c). The instant Complaint is limited to ensuring that MISO has the requisite Tariff-based *mechanism* to effectuate the Company's cost recovery—which is the same relief that the Commission recently granted to a similarly situated utility in *Consumers Energy*.[11]

Both SIGE and MISO agree that (1) the existing MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff") does not include a mechanism for the Company to recover costs associated with complying with the DOE Order; and (2) MISO lacks Tariff authority to unilaterally offer the Company a section 202(c) rate agreement. Accordingly, SIGE requests that the Commission exercise its authority pursuant to FPA sections 202(c) and 309 to order MISO to adopt a Tariff revision to provide a cost recovery and allocation mechanism for the

---

9 Understanding that the DOE may issue a subsequent order, or subsequent orders, extending the Company's obligation to keep Culley Unit 2 available, the Company reserves the right to determine at a later date whether it will seek cost recovery on a seriatum basis, corresponding to the duration of a given order, or for a longer period, covering more than one order.

10 *See* Consumers Complaint Order, 192 FERC ¶ 61,158 at P 42 ("While this order approves the cost allocation methodology in the Proposed Tariff Provision, it does not approve recovery of actual costs…Consumers must petition the Commission in a separate proceeding at a later date for approval to recover specific DOE Order Costs before ratepayers can be charged for such costs.") For the avoidance of doubt, consistent with Section 202(c)'s cost recovery language, the Company reserves all rights to make a demonstration of its just and reasonable Order Costs (net of market revenues) in a subsequent Section 202(c) filing discussed herein.

11 *See id.* P 42; *see also* Consumers Rehearing Order, 193 FERC ¶ 61,228 at P 37.

Company's Order Costs in the form set forth in Attachment A hereto ("Cost Recovery Mechanism").[12] SIGE requests that the proposed MISO Tariff revision, implementing the Cost Recovery Mechanism, be effective as of the issuance of the DOE Order on December 23, 2025, or such other date as the Commission determines will still permit recovery of the Company's Order Costs back to the referenced date of the DOE Order.[13]

I. EXECUTIVE SUMMARY

Pursuant to the DOE Organization Act, the authority under section 202(c) to "determine[] 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" is vested in the Secretary of Energy. That section's authority to "order such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest" is similarly vested in the Secretary. The Commission's role under this particular statutory framework is limited to cost recovery.[14]

As detailed below, Culley Unit 2 is a roughly 103.7 MW coal-fired generating station that had been scheduled to cease operations as of December 31, 2025. As soon as the DOE Order was

[12] The Cost Recovery Mechanism SIGE is proposing materially tracks the one proposed by Consumers Energy in Docket EL25-90-000.

[13] The Company believes that FPA sections 202(c) and 309 provide ample authority for the Commission to grant the relief requested herein. Indeed, in *Consumers Energy*, the Commission relied solely on FPA section 202(c) to grant the requested relief. However, in an abundance of caution, if the Commission finds it must invoke its FPA section 206 authority to grant the relief requested herein, SIGE moves for relief under Section 206 in the alternative. *See infra* Section V. Under section 206, the Commission could make the requested Tariff revision effective as of the date of this Complaint.

[14] *See* Consumers Rehearing Order, 193 FERC ¶ 61,228 at P 31. ("Under the DOE Organization Act, the determination of the need for operation of the Campell Plant rests solely with DOE; the Commission's responsibility is to provide 'for compensation or reimbursement' of the costs of operation.") (citations omitted).

issued, SIGE began incurring and will continue to incur costs to comply with the DOE Order's directive to "take all measures necessary to ensure that the Culley Unit 2 is available to operate" for the duration of the DOE Order.[15] The precise Order Costs will not be known until after the DOE Order expires on March 23, 2026. Thereafter, SIGE will make a separate request to the Commission under section 202(c) for the "compensation or reimbursement" of its Order Costs once known, net of market revenues, as provided by the statute.[16]

The more immediate issue is that the MISO Tariff currently does not contain a mechanism for SIGE to recover the costs being incurred as a result of the DOE Order—nor does it contain a mechanism to allocate such costs to reflect the nature of the emergency declared pursuant to section 202(c). This Complaint, therefore, asks the Commission to order MISO to revise its Tariff to provide for allocation of the Company's (later-to-be-determined) Order Costs, net of market revenues. This relief is necessary and appropriate for several reasons. For its part, SIGE has no contractual privity or Tariff authority to allocate costs directly to MISO customers. Ordering Paragraph E of the DOE Order instructs SIGE to "file with the Federal Energy Regulatory Commission Tariff revisions or waivers necessary to effectuate this order" and the same paragraph makes clear that "[r]ate recovery is available pursuant to 16 U.S.C. § 824a(c)."[17] Further, DOE sent "carbon copies" of the DOE Order to each sitting FERC Commissioner.[18]

The Commission's duties and authority to address this Complaint and issue the requested relief are found in sections 202(c), 306, and 309 of the FPA. Importantly, cost recovery under

---

15 SIGE notes that Culley Unit 2 is currently in a maintenance outage but is preparing Culley Unit 2 to be offered into the MISO market and to produce energy when dispatched.

16 *See supra* note 9.

17 DOE Order, at Ordering Paragraph E.

18 *Id.*

section 202(c) does not invoke the normal ratemaking strictures of FPA sections 205 or 206. Section 202(c) provides independent authority to empower the Commission to "prescribe by supplemental order such terms as it finds to be just and reasonable, including the compensation or reimbursement which should be paid to or by any such party."[19] And, to the extent necessary, FPA section 309 supplements the Commission's authority to take action to implement its section 202(c) responsibilities. Specifically, FPA section 309 grants the Commission "power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules, and regulations as it may find necessary or appropriate to carry out the provisions of this chapter."[20] To effectuate the Company's right to recover the costs of complying with the DOE Order, the MISO Tariff must be amended to create a recovery mechanism. In the absence of an agreement between the parties affected by a 202(c) order, the Commission has the responsibility for determining cost recovery and allocation. As noted above, the actual costs, if any, SIGE seeks to recover will be the subject of a separate filing with the Commission. However, at this juncture, FPA section 309 authorizes the Commission to take measures to ensure its ability "to carry out" its role, pursuant to section 202(c), by requiring adoption of the Cost Recovery Mechanism.

Finally, the relief requested herein meets the "just and reasonable" standard of section 202(c)(1). In addition to providing MISO the authority to implement a mechanism for cost recovery, SIGE asks the Commission to order MISO to adopt specific Tariff provisions to allocate its Order Costs (net of market revenues) proportionally to load in MISO Zones 1 through 7 – referred to in the DOE Order as the northern and central regions of MISO.[21] This proposed cost

---

[19] 16 U.S.C. §824a(c)(1).

[20] 16 U.S.C. § 825h.

[21] DOE Order at 2.

allocation is just and reasonable because, as the Commission found in *Consumers Energy*, under section 202(c), costs should be allocated based on the scope and nature of the emergency that prompted issuance of the order in question.[22] Further, the DOE Order's emergency declaration is substantially based on concerns about resource adequacy in MISO generally, and the northern and central regions in particular.[23] In other words, the beneficiaries for cost allocation purposes are best determined by reference to the Secretary's definition of the emergency. Under such a regional allocation, Indiana load will of course pay its fair share of SIGE's Order Costs (net of market revenues) because, as the DOE Order points out, MISO Zones 1 through 7 (*i.e.*, the northern and central zones) include Indiana.[24] But SIGE believes that, whatever the Order Costs turn out to be after netting market revenues, they should be allocated regionally rather than only to the State of Indiana. SIGE customers are already paying for the cost to fulfill the capacity needs of Zone 6.

In sum, the Commission's duties and authority to address this cost allocation are clear. SIGE respectfully requests that the Commission set a 10-day comment period on this Complaint, and issue an order at the earliest opportunity directing MISO to adopt the proposed Cost Recovery Mechanism in the form set forth in Attachment A.

---

[22] Consumers Complaint Order, 192 FERC ¶ 61,158 at P 39.

[23] Because the DOE Order cites the "northern and central zones," SIGE believes the best read of the DOE Order is that the emergency identified exists in Zones 1 through 7 and would not reach "MISO South." DOE Order, at 2. In *Consumers Energy* the Commission found that it was reasonable to interpret the DOE Order's reliance on MISO statements in the Planning Resource Auction Results for Planning Year 2025-2026, which highlighted that new resources "were insufficient to offset the negative impacts of decreased accreditation, suspension/retirements and external resources" in the MISO North and MISO Central regions, as indicating concerns were the primary driver for the emergency order. Consumers Complaint Order, 192 FERC ¶ 61,158 at P 40. In the Consumers Rehearing Order, the Commission acknowledged that the emergency order in question referenced shortfalls and concerns *outside* of MISO's Local Resources Zones 1 through 7 but continued to rely on the Commission's original finding that the intended scope of the emergency in the DOE's order was focused on Local Resource Zones 1 through 7. Consumers Rehearing Order, 193 FERC ¶ 61,228 at P 38.

[24] DOE Order at 2.

II. BACKGROUND

A. The Parties

1. Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South

SIGE is a wholly owned indirect subsidiary of CenterPoint that operates both an electric utility division and a gas utility division in Indiana. SIGE's electric utility division is a vertically integrated public utility serving electric wholesale and retail customers in seven counties in southwest Indiana. The electric utility division owns generation, transmission, and distribution facilities and serves approximately 153,400 retail customers. SIGE's gas utility division transports and distributes gas in southwestern Indiana and has gas storage in its service territory that it uses to serve its approximately 115,990 retail customers, all subject to Indiana regulation.[25] SIGE is a member of MISO, the Reliability First Corporation, and the North American Electric Reliability Corporation ("NERC").

2. MISO

MISO is an Independent System Operator and Regional Transmission Organization and is authorized by the Commission to provide open access transmission service and to administer wholesale energy, capacity, and ancillary services markets in portions of the Midwest region of the United States, as well as certain other regions. MISO also administers the MISO Tariff, which governs such markets. MISO includes ten separate zones. MISO's northern and central regions are Zones 1 through 7.

---

[25] SIGE's gas utility division is exempt from Natural Gas Act (the "NGA") regulation under the NGA's §1(c) Hinshaw provision.

B. Factual Background

1. The Culley Plant

The Culley Plant is a coal-fired electric generation plant located in Warrick County, Indiana, with a nameplate capacity of approximately 368.9 MW. The Culley Plant consists of two units, both of which are wholly owned and operated by SIGE:

- Culley Unit 2 commenced commercial operations in 1966 and has a nameplate capacity of 103.7 MW; and
- Culley Unit 3 commenced commercial operations in 1973 and has a nameplate capacity of approximately 265.2 MW.

Culley Unit 2 is the Company's oldest, smallest, and least efficient coal unit and given that the unit has long been slated for retirement, minimal capital investment has been made in the last decade. Culley Unit 2's non-reheat turbine design makes the unit inherently less efficient than Culley Unit 3, resulting in higher dispatch costs. As a result, the Culley Unit 2 operates infrequently within the MISO market, with an annual capacity factor of roughly 25%. MISO reviewed the Company's suspension request for Culley Unit 2 and found no reliability criteria violations. Additionally, the Independent Market Monitor ("IMM") confirmed that the suspension request complies with market rules and supports efficient, least-cost regional planning.

Every three years, SIGE prepares, and submits, an Integrated Resource Plan ("IRP") to the Indiana Utility Regulatory Commission ("IURC"). Each IRP evaluates the costs of continuing to operate certain existing, but aging, generation resources compared to the costs of retiring and replacing the generation with different resources. The retirement analysis in three of SIGE's last four IRPs – specifically, its 2016, 2019/2020 and 2023 IRPs[26] – concluded that SIGE could not

---

[26] SIGE's 2016 IRP submitted to the IURC (Cause No. 44890) on December 19, 2016 (SIGECO 2016 IRP. (n.d.). Indiana Utility Regulatory Commission. *https://www.in.gov/iurc/files/SIGECO-2016-IRP.pdf*, *See* Executive Summary, Section VI. The Preferred Portfolio and Executive Summary, Section VII. Next

continue to operate Culley Unit 2 beyond October 2023 without making some investment, or beyond December 2025 without making significant investment, to bring the facility into compliance with then applicable environmental standards. Based on that analysis, SIGE concluded its customers would pay lower costs over the next two decades by retiring Culley Unit 2 and investing in other generation resources. Consequently, Culley Unit 2 was scheduled to cease operations at the end of calendar year 2023; but later extended to December 31, 2025 because it was determined, at the time, to be a lower cost option for its customers. On November 26, 2024, SIGE timely submitted an Attachment Y Notice to MISO to suspend operation of Culley Unit 2 effective December 31, 2025; MISO approved the request on June 3, 2025, after performing its reliability analysis. Pursuant to commitments SIGE made in an IURC approved settlement agreement in Cause No. 45990 (IURC 2/3/2025, as modified on rehearing dated 3/19/2025), SIGE had Culley Unit 2 scheduled to cease operations and be retired from its utility records on December 31, 2025.

2. The DOE Order

The DOE Order states that MISO's "year-round resource adequacy concerns are well documented" and "that an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electric energy,

---

Steps); SIGE's 2019/2020 IRP submitted to the IURC (Cause No. 45397) on June 29, 2020 (2019–2020 Vectren IRP Volume 1 of 2. (n.d.). Indiana Utility Regulatory Commission. *2019-2020-Vectren-IRP-Volume-1-of-2.pdf*, See Executive Summary, Section VI. The Preferred Portfolio); SIGE's 2023 IRP submitted to the IURC (Cause No. 45897) on May 26, 2023 (2022–2023 CNP IRP Volume 1 of 2 (Redacted). (n.d.). Indiana Utility Regulatory Commission. *2022-2023-CNP-IRP-Volume-1-of-2-Redacted.pdf*, ***See Executive Summary***, Section VI. The Preferred Portfolio); and SIGE's 2025 IRP submitted to the IURC (Cause No. 46333 on December 5, 2025 (CEIS 2025 IRP Volume 1 of 2. (n.d.). Indiana Utility Regulatory Commission. *https://www.in.gov/iurc/files/CEIS_2025_IRP_Volume_1_of_2.pdf*, See Executive Summary, Preferred Portfolio).

and other causes."[27] The DOE Order determined that the "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."[28] The DOE Order also points out that "MISO's Planning Resource Auction Results for Planning Year 2025-26, released in April 2025, note that for the northern and central zones, which includes Indiana, 'new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources.'"[29]

Based on the foregoing determination, the DOE Order directs the Company and MISO to "take all measures necessary to ensure that Culley Unit 2 is available to operate" until the DOE Order's expiration on March 23, 2026.[30] The DOE Order explains that "[r]ate recovery is available pursuant to 16 U.S.C. § 824a(c)" and directs the Company "to file with the Federal Energy Regulatory Commission Tariff revisions or waivers necessary to effectuate" the DOE Order.[31] The DOE Order also directs MISO, among other things, to "take every step to employ economic dispatch of the Culley Unit 2 to minimize cost to ratepayers"[32] and "provide the Department of

---

27 DOE Order at 1.

28 *Id.* at 5.

29 *Id.* at 2 (citation omitted). The language from the DOE Order is virtually identical to the language in the relevant emergency order directed at Consumers Energy. *See* U.S. Dep't of Energy, May 30, 2025 Emergency Order No. 202-25-3, at 2 (May 30, 2025) https://www.energy.gov/sites/default/files/2025-05/Midcontinent%20Independent%20System%20Operator%20%28MISO%29%20202%28c%29%20Order_1.pdf. Therefore, the Company assumes that the DOE Order is focused on the same geographic location as was at issue in *Consumers Energy,* i.e., MISO Local Resource Zones 1 through 7.

30 DOE Order at Ordering Paragraph A.

31 *Id.* at Ordering Paragraph E.

32 *Id.* at Ordering Paragraph A.

Energy . . . with information concerning the measures it has taken and is planning to take to ensure the operational availability and economic dispatch of Culley Unit 2 consistent with this order."[33]

3. Company Actions to Comply with the DOE Order

Upon receiving the DOE Order, SIGE has undertaken significant efforts to comply with its directives, including ensuring adequate fuel supply, reviewing and planning related to ongoing operations and maintenance and capital investments, and numerous other undertakings.

In accordance with the DOE 202(c) Order, SIGE is entitled to cost recovery of the costs associated with SIGE's efforts to comply with the order.[34] SIGE has coordinated with MISO to facilitate the attached proposed Schedule {XYZ} (Attachment A), which provides for SIGE to submit a FPA Section 202(c) filing at the Commission to recover all costs to comply with the DOE 202(c) Order. The Company intends to establish a regulatory asset to account for all costs of running Culley Unit 2 from the date the DOE Order was issued and will seek recovery of such costs in a future filing. The Cost Recovery Mechanism being requested herein will be the Tariff mechanism for the recovery of Order Costs, subject to Commission approval.

C. Overview of FPA Section 202 and DOE's Implementing Regulations

FPA section 202(c) was established by the Public Utility Act of 1935 and originally provided the emergency authority to the Federal Power Commission.[35] In 1977, the DOE Organization Act transferred the authority to determine the existence of an emergency to the Secretary of the Energy.[36]

---

33 *Id.* at Ordering Paragraph D.

34 *Id.* at Ordering Paragraph E.

35 *See* Public Utility Holding Company Act of 1935, Pub. L. No. 74-333, pt. II at 849 (1935) (codified at 16 U.S.C. § 824a(c)).

36 *See* Department of Energy Organization Act, Pub. L. No. 95-91, tit. III, 91 Stat. 577-78 (1977) (codified at 42 U.S.C. § 7151). As a result, the word "Commission" refers to the Secretary of Energy for purposes of determining the emergency and ordering the emergency generation.

Section 202(c) of the FPA provides, in relevant part, as follows:

> During the continuance of any war in which the United States is engaged, or whenever the Commission determines that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes, the Commission shall have authority, either upon its own motion or upon complaint, with or without notice, hearing, or report, to require by order such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest. *If the parties affected by such order fail to agree upon the terms of any arrangement between them in carrying out such order, the Commission, after hearing held either before or after such order takes effect, may prescribe by supplemental order such terms as it finds to be just and reasonable, including the compensation or reimbursement which should be paid to or by any such party*.

16 U.S.C. 824a(c)(1) (emphasis added).

In 1981, the DOE promulgated a rule to implement the rate aspects of FPA section 202(c). That rule provides, in relevant part:

> In the event that the DOE determines that an emergency exists under [FPA] section 202(c), and the "entities" are unable to agree on the rates to be charged, *the DOE shall* prescribe the conditions of service and *refer the rate issues to the Federal Energy Regulatory Commission for determination by that agency in accordance with its standards and procedures*.

10 C.F.R. § 205.376 (emphasis added) ("DOE Referral Regulation").

III. RELIEF REQUESTED

SIGE requests that the Commission direct MISO to revise the MISO Tariff to include a Cost Recovery Mechanism in the form included herewith as Attachment A in such manner as to provide recovery of SIGE's Order Costs dating back to the issuance of the DOE Order.

IV. ARGUMENT

A. The Company Has a Right to Recover Costs Associated with the DOE Order, and Such Costs Can Be Determined After-the-Fact

FPA section 202(c) confers the right to recover costs associated with an order issued pursuant to its emergency authority. When the parties affected cannot agree on such costs, the statute charges the Commission with the responsibility to determine them.[37] Importantly, FERC's rate determinations pursuant to section 202(c) can occur after a section 202(c) order terminates, and after the conclusion of the compelled generation or provision of jurisdictional service.

1. Parties Subject to a Section 202(c) Order Are Entitled to Recover Associated Costs, Subject to Commission Approval

There can be no question that SIGE has a right to recover its Order Costs, net of market revenues. This is confirmed by the plain language of FPA section 202(c), the DOE Referral Regulation, and the DOE Order, itself:

- FPA section 202(c): If the parties affected by such order fail to agree upon the terms of any arrangement between them in carrying out such order, the Commission, after hearing held either before or after such order takes effect, may prescribe by supplemental order such terms as it finds to be just and reasonable, *including the compensation <u>or reimbursement</u>* which should be paid to or by any such party.[38]
- DOE Referral Regulation: In the event that the DOE determines that an emergency exists under [FPA] section 202(c), and the "entities" are unable to agree on the rates to be charged, *the DOE shall* prescribe the conditions of service and *refer the rate*

[37] *See* Consumers Rehearing Order, 193 FERC ¶ 61,228 at P 37.

[38] 16 U.S.C. § 824a(c)(1) (emphasis added).

issues to the Federal Energy Regulatory Commission for determination by that agency in accordance with its standards and procedures.[39]

- DOE Order: "Rate recovery is available pursuant to [FPA section 202(c)]."[40]

Indeed, recovery of Order Costs is mandated by the U.S. Constitution. Specifically, the Fifth Amendment Takings Clause bars the federal government from taking private property for public use without just compensation.[41] For the avoidance of doubt, SIGE only seeks to recover its Order Costs *net of market revenues* earned from Culley Unit 2's operation.

2. Pursuant to the Commission's Section 202(c) Rate Authority, Costs Can Be Determined and Recovered *After* the Emergency Generation or Provision of Jurisdictional Service Without Violating the Filed Rate Doctrine

As described below, both the plain language of section 202(c) and prior Commission precedent demonstrate that appropriate compensation can be determined and recovered after the term of an order declaring an emergency and/or requiring provision of jurisdictional service and costs have begun to be incurred. Moreover, the prior notice requirements and related filed rate doctrine and rule against retroactive ratemaking pursuant to FPA sections 205 and 206 do not apply in the context of determining compensation pursuant to FPA section 202(c), which provides independent ratemaking authority and includes its own "just and reasonable" standard.

First, section 202(c)'s plain language: After an emergency section 202(c) order "takes effect," the statute expressly contemplates "supplemental" orders regarding "compensation or

---

39 10 C.F.R. § 205.376 (emphasis added).

40 DOE Order at Ordering Paragraph E.

41 U.S. CONST. AMEND. V ("[N]or shall private property by taken for use, without just compensation."); *see, e.g.*, *Duquesne Light Co. v. Barasch*, 488 U.S. 299, 308 (1989) ("If the rate does not afford sufficient compensation, the State has taken the use of utility property without paying just compensation . . . .").

reimbursement."[42] The use of the word "reimbursement" indicates an after-the-fact approach. Together, this language demonstrates that, unlike FPA section 205 (which requires prior notice and approval of rates), or section 206 (which allows only prospective fixing of rates or charges by the Commission), the Commission's rate authority under section 202(c) is broader, and not constrained in the same ways that it is under sections 205 and 206.

Second, Commission precedent: SIGE's proposed Cost Recovery Mechanism is consistent with the Schedule that the Commission ordered MISO to file for Consumers Energy in Docket Nos. EL25-90-000 and AD25-14-000.[43] Indeed, *Consumers Energy* confirms the retrospective nature of cost recovery through a subsequent filing to be made "at a later date for approval to recover specific DOE Order Costs."[44]

Third, the inapplicability of constraints on the Commission's ratemaking authority pursuant to FPA sections 205 and 206: The Commission's core responsibility of ensuring just and reasonable rates for jurisdictional sales and services is typically carried out pursuant to FPA sections 205 and 206 – and it is subject to certain well-established doctrines that arise directly from the statutory language of those two FPA provisions.

Section 205 of the FPA requires public utilities to file with the Commission any rates and charges that are subject to the Commission's jurisdiction, with the required prior notice, and it requires the Commission to ensure the justness and reasonableness of such rates.[45] A public utility

---

42 16 U.S.C. § 824a(c).

43 Consumers Complaint Order, 192 FERC ¶ 61,158 at P 35; *see also U.S. Dept. of Energy*, 107 FERC ¶ 61,258 (2004).

44 Consumers Complaint Order, 192 FERC ¶ 61,158 at P 42. *See also U.S. Dept. of Energy*, 101 FERC ¶ 61,389 (2002); *U.S. Dept. of Energy*, 107 FERC ¶ 61,258.

45 16 U.S.C. § 824d(c).

is only authorized to charge the rate on file with the Commission, and changes to such rates must be prospective.[46]

Section 206 of the FPA empowers the Commission, upon its own motion or in response to a complaint, to address existing rates that may have become unjust or unreasonable.[47] If FERC makes such a determination, it has the authority to determine the "just and reasonable rate, charge, classification, rule, regulation, practice or contract to be thereafter observed" – but this authority is prospective.

These statutory provisions "mandating the open and transparent filing of rates and broadly proscribing their retroactive adjustment are known collectively as the 'filed rate doctrine.'"[48] The filed rate doctrine prevents "'a regulated seller of [power] . . . from collecting a rate other than the one filed with the Commission,' and 'the Commission itself' cannot retroactively 'impos[e] a rate increase for [power] already sold.'"[49] Similarly, the rule against retroactive ratemaking "prohibits the Commission from adjusting current rates to make up for a utility's over- or under-collection in prior periods."[50]

The prior notice and other strictures associated with ratemaking pursuant to FPA sections 205 and 206 do not apply under section 202(c) because those requirements are recognized to be rooted in the statutory language of FPA sections 205 and 206.[51] In contrast to FPA sections 205(c)

---

46 *W. Deptford Energy, LLC v. FERC*, 766 F.3d 10, 12 (D.C. Cir. 2014) ("[U]tilities are forbidden to charge any rate other than the one on file with the Commission."); *Okla. Gas & Elec. Co. v. FERC*, 11 F.4th 821, 829 (D.C. Cir. 2021).

47 16 U.S.C. § 824e(a).

48 *Old Dominion Elec. Coop. v. FERC*, 892 F.3d 1223, 1226-27 (D.C. Cir. 2018).

49 *Id.* at 1227 (quoting *Ark.-La. Gas Co. v. Hall*, 453 U.S. 571, 578 (1981)).

50 *Towns of Concord, Norwood, & Wellesley Mass. v. FERC*, 955 F.2d 67, 71 n.2 (D.C. Cir. 1992).

51 *Id.* at 71-72 ("[I]t is generally agreed that with respect to the Federal Power Act, the filed rate doctrine rests on two provisions: section 205(c), which requires utilities to file rate schedules with the

and 206(a), FPA section 202(c) does not have a prior notice requirement and it does not mandate the filing of rate schedules or the prospective fixing of charges. Rather, in the absence of agreement between "the parties affected by such [emergency] order," section 202(c) permits the Commission to "prescribe by supplemental order such terms as it finds to be just and reasonable, including the compensation or reimbursement which should be paid to or by any such party."[52]

The independent nature of the Commission's rate authority under section 202(c) is further supported by the fact that it is only triggered if the parties affected by the relevant 202(c) order are unable to reach an agreement.[53] In *San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Services*, the Commission explained that "[t]he statute provides *no role* for the Commission in the event the parties agree on the rates that will apply to the transactions [pursuant to FPA section 202(c)]."[54] The primacy that the FPA accords to the 202(c) rate determination reached by agreement of the parties is very different from traditional ratemaking rules under sections 205 and 206, which prescribe detailed filing and cost support requirements.[55]

Finally, section 202(c) includes its own "just and reasonable" standard when making rate determinations.

For all of the foregoing reasons, the recovery of costs associated with a FPA section 202(c) order is separate and distinct from rate determinations made under FPA sections 205 and 206.

Commission, and section 206(a), which allows the Commission to fix rates and charges, but only prospectively.") (footnotes omitted).

52 16 U.S.C. § 824a(c)(1).

53 *Id.* ("If the parties affected by such order fail to agree upon the terms of any arrangement between them in carrying out such order, the Commission, . . . may prescribe . . . .").

54 97 FERC ¶ 61,275, at 62,196 (2001) (emphasis added) (subsequent history omitted).

55 *See, e.g.*, 18 C.F.R § 35.13 and § 385.206 (2024).

B. The Commission Should Require MISO to Revise the Tariff to Include the Proposed 202(c) Cost Recovery Mechanism

1. Regional Allocation of Costs is Appropriate to Reflect the Scope and Nature of the Emergency Identified by the Secretary

As discussed above in Section II.B.2, the DOE Order identifies reliability risks in MISO, particularly in the northern and central zones, as the basis for declaring an emergency and ordering the continued operation of Culley Unit 2 until March 23, 2026. In light of the scope and nature of the declared emergency, allocating SIGE's Order Costs (net of market revenues) to load serving entities ("LSEs") in MISO's northern and central zones (which as the DOE Order notes, include Indiana) comports with section 202(c)'s just and reasonable standard because the DOE Order identified reliability risks in those MISO zones as the basis for declaring the emergency.

While this case is not governed by sections 205 or 206, general beneficiary pays/cost-causation principles commonly invoked in connection with the Commission's rate authority nevertheless provide a useful framework for analyzing cost allocation under 202(c).[56] Here, the Secretary of Energy has determined the scope and nature of an emergency, and the compelled generation or jurisdictional service needed to address it. Consequently, to determine appropriate cost recovery pursuant to FPA section 202(c), the beneficiary pays/cost-causation determination should track the emergency identified in the 202(c) order at issue. Any other approach would create a risk of conflict between the emergency 202(c) order and a subsequent analysis of cost-causation and benefits. In *Consumers Energy*, the Commission held that, in the context of a 202(c) order, applying the cost causation principle that requires "all approved rates reflect to some degree

[56] The beneficiary pays/cost-causation principle requires costs to be allocated to those who cause the costs to be incurred and reap the resulting benefits. *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41, 87 (D.C. Cir. 2014) (citing *Nat'l Ass'n of Regul. Util. Comm'rs v. FERC*, 475 F.3d 1277, 1285 (D.C. Cir. 2007)).

the costs actually caused by the customer who must pay them"[57] means allocating costs in accordance with the scope of the emergency described in the relevant 202(c) order.[58]

As applied here, this means that LSEs in MISO's northern and central zones should share the costs associated with the DOE Order on a load ratio share basis.[59] The geographic scope identified in the DOE Order is virtually identical to the scope identified in *Consumers Energy* and thus it makes sense for the relief in this case to track the relief granted in *Consumers Energy* as far as cost allocation is concerned. The Cost Recovery Mechanism set forth in Attachment A is designed to accomplish this outcome.

2. No MISO Tariff Provision Presently Would Permit Such Allocation and Recovery

Currently, there is no MISO Tariff provision that would permit SIGE's costs of complying with the DOE Order to be allocated to LSEs in MISO's northern and central zones, which, if unaddressed, would effectively prevent SIGE from recovering its costs via FPA section 202(c) even though, as discussed above, that statute, as well as DOE regulations and the DOE Order, all provide for full cost recovery. While full cost recovery is clearly contemplated, there is no provision in the MISO Tariff that would allow SIGE to recover costs associated with the DOE Order, SIGE has no authority to bill anyone in MISO for such costs, and MISO cannot unilaterally offer SIGE a section 202(c) rate agreement. Therefore, in order for SIGE to have a means of

[57] Consumers Complaint Order, 192 FERC ¶ 61,158 at P 38 (citation omitted).

[58] Consumers Complaint Order at P 39 ("In applying the cost causation principle here, we find that it is just and reasonable for the cost allocation method to allocate costs in accordance with the scope of the emergency as described in the DOE Order.").

[59] SIGE has proposed a load ratio share basis consistent with the proposed Cost Recovery Mechanism that was approved in *Consumers Energy*. *See id.* PP 35, 43. SIGE notes that MISO's compliance filing to define and describe "load ratio share" remains pending in Docket No. ER25-3425-000 and the proposed Cost Recovery Mechanism is intended to reflect the MISO's definition once approved by the Commission.

recovering the costs that it has a right to recover, the MISO Tariff must be amended to include an appropriate recovery mechanism.

C. The Commission Has Authority Pursuant to FPA Section 309 to Require Revisions to the MISO Tariff to Implement the DOE Order

FPA section 309 authorizes the Commission "to perform any and all acts . . . as it may find necessary or appropriate to carry out the provisions of [the FPA]."[60] Courts have made clear that the Commission has significant authority under section 309 when employed to give effect to other substantive authority under the Act.[61] Here, the Commission's underlying substantive authority is clearly provided by section 202(c). Because section 202(c) makes the Commission responsible for ensuring just and reasonable compensation for emergency generation or service, and because the MISO Tariff does not presently have a mechanism for addressing the Company's Order Costs, the Commission should order MISO to implement the Cost Recovery Mechanism the Company has included in Attachment A. This requested relief falls squarely within the Commission's broad implementation authority under FPA section 309 and is "necessary . . . to carry out the provisions of"[62] FPA section 202(c).

V. ALTERNATIVE REQUEST FOR RELIEF PURSUANT TO FPA SECTION 206

The Company believes that FPA sections 202(c) and 309 provide ample authority for the Commission to grant the relief requested herein. Nonetheless, if the Commission finds it must invoke its FPA section 206 authority to grant the relief requested herein, SIGE moves for relief under section 206 in the alternative. Under section 206, the Commission could make the requested Tariff revision effective as of the date of this Complaint.

---

[60] 15 U.S.C. § 717o.

[61] *TNA Merchant Projects, Inc. v. FERC*, 857 F.3d 354, 359 (D.C. Cir. 2017); *Verso Corp. v. FERC*, 898 F.3d 1, 11-12 (D.C. Cir. 2018); *Xcel Energy Servs. Inc. v. FERC*, 815 F.3d 947 (D.C. Cir. 2016).

[62] 16 U.S.C. § 825h.

"Section 206 permits, indeed requires, the Commission to determine whether an existing rate is 'unjust, unreasonable, unduly discriminatory, or preferential.'"[63] This statutory mandate includes determining whether a rate is unjust and unreasonable *as applied* to certain parties or to certain circumstances.[64] Upon reaching a determination that an existing rate is unjust and unreasonable, section 206 mandates that the Commission "determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order."[65]

As explained above, the Secretary of Energy has determined "that an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electricity, and other causes"[66] and that the "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."[67]

---

63 *Emera Me. v. FERC*, 854 F.3d 9, 21 (D.C. Cir. 2017) (quoting 16 U.S.C. § 824e(a)) (alteration incorporated).

64 *See, e.g.*, *Pub. Serv. Elec. & Gas Co. v. FERC*, 989 F.3d 10, 18 (D.C. Cir. 2021) ("[T]he Commission reasonably found that the solution–based DFAX method was unjust and unreasonable as applied to the Artificial Island Project."); *Am. Wind Energy Ass'n v. Sw. Power Pool, Inc.*, 167 FERC ¶ 61,033 at P 49 (2019) ("We find that SPP's membership exit fee, as applied to non-transmission owners, is unjust and unreasonable because it creates a barrier to SPP membership for non-transmission owners and because it appears to be excessive based on the record before us."), *order denying stay*, 168 FERC ¶ 61,006; *PJM Interconnection, L.L.C.*, 169 FERC ¶ 61,049 at P 138 (2019) (opening an FPA section 206 proceed to, *inter alia*, examine "the justness and reasonableness of PJM's minimum run-time requirements as applied to Capacity Storage Resources"); *PJM Interconnection, L.L.C.*, 137 FERC ¶ 61,145 at P 99 (2011) ("[T]he ultimate vehicle that will be required to establish that mitigation rules are unjust and unreasonable as applied to a particular project is a section 206 complaint.") (subsequent history omitted).

65 16 U.S.C. § 824e(a).

66 DOE Order, at 1.

67 *Id.* at 5.

SIGE will incur costs associated with the DOE Order, but the MISO Tariff does not presently include a mechanism that would allow MISO to compensate the Company for such costs or allocate those costs to load in the MISO region.

The MISO Tariff is thus unjust and unreasonable as applied to the Company and its compliance with the DOE Order, and the Commission should order MISO to adopt a Tariff revision to provide a Cost Recovery Mechanism for SIGE's Order Costs net of market revenues. Should the Commission proceed under FPA section 206, however, SIGE respectfully notes that the refund effective date that the Commission establishes pursuant to FPA section 206(b) has no bearing on, and does not limit, SIGE's right to recover the Order Costs it has already incurred and will continue to incur going forward.

VI. REQUEST FOR FAST TRACK PROCESSING AND EXPEDITED ACTION

SIGE respectfully requests Fast Track processing and expedited action on this Complaint under Rule 206(h) of the Commission's Rules of Practice and Procedure. The Complaint merits expeditious resolution because SIGE must establish a Cost Recovery Mechanism for the costs that have been incurred, and are continuing to be incurred, to comply with the DOE Order. Expeditious action from the Commission to modify the MISO Tariff is appropriate in order to avoid challenges to SIGE's right to cost recovery.

SIGE respectfully requests that the Commission issue its ruling on the Complaint as soon as possible. SIGE also respectfully requests a shortened comment period of ten days.

VII. ADDITIONAL INFORMATION REQUIRED BY RULE 206 OF THE COMMISSION'S RULES OF PROCEDURE

To the extent not already provided herein, the Company provides the following additional information required by Rule 206(b) of the Commission's Rules of Practice and Procedure:

1. Clearly identify the action or inaction which is alleged to violate applicable statutory standards or regulatory requirements; explain how the action or inaction violates applicable statutory standards or regulatory requirements.

Despite SIGE's right to recover costs incurred associated with the DOE Order, the MISO Tariff does not presently include a mechanism for the recovery and allocation of such costs, and MISO lacks Tariff authority to unilaterally offer SIGE a section 202(c) rate agreement. The Commission should therefore require MISO to revise the MISO Tariff to include the proposed Cost Recovery Mechanism.

2. Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the complainant.

The information in Sections I through V of this Complaint sets forth the business, commercial, and economic issues at stake for the Company.

3. Make a good faith effort to quantify the financial impact or burden (if any) created for the complainant as a result of the action or inaction.

SIGE intends to seek recovery of all costs for the continued operation of Culley Unit 2; and, as such, intends to establish a regulatory asset to track all costs of operating Culley Unit 2 from the date of the DOE Order. The total of such costs, net of market revenues, is not presently known. After the DOE Order expires, any costs that SIGE seeks to recover through the section 202(c) Cost Recovery Mechanism will be addressed in a future filing with the Commission.

4. Indicate the practical, operational, or other nonfinancial impacts imposed as a result of the action or inaction, including, where applicable, the environmental, safety or reliability impacts of the action or inaction.

The DOE Order concludes that it is in the public interest for the Company to ensure that Culley Unit 2 is "available to operate" in order to address the emergency conditions identified by the Secretary. The Company has a constitutional and statutory right to recover costs associated with the DOE Order. Failure of the Commission to provide the relief requested herein would conflict with the DOE Order and create unfair and unwarranted risk for the Company's right to cost recovery.

5. **State whether the issues presented are pending in an existing Commission proceeding or a proceeding in any other forum in which the complainant is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum.**

The issues raised in this Complaint are not pending in an existing Commission proceeding or a proceeding in any other forum in which SIGE is a party. Resolution of these issues cannot be achieved in any pending docket.

6. **State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief.**

The specific relief requested is identified in Sections I and III of this Complaint.

7. **Include all documents that support the facts in the complaint in possession of, or otherwise attainable by, the complainant, including, but not limited to, contracts and affidavits.**

The only relevant document is the DOE Order, which is attached as Attachment C.

8. **State (i) whether the Enforcement Hotline, Dispute Resolution Service, tariff-based dispute resolution mechanisms, or other informal dispute resolution procedures were used, or why these procedures were not used; (ii) whether the complainant believes that alternative dispute resolution (ADR) under the Commission's supervision could successfully resolve the complaint; (iii) what types of ADR procedures could be used; and (iv) Any process that has been agreed on for resolving the complaint.**

As discussed above, SIGE and MISO have cooperated extensively to evaluate and implement their respective responsibilities pursuant to the DOE Order. However, the MISO Tariff does not include a mechanism for the Company to recover costs associated with the DOE Order, and MISO does not possess unilateral authority to offer the Company a 202(c) rate agreement. Therefore, SIGE believes Commission action on this Complaint is required in order to effectuate the relief requested.

9. Include a form of notice of the complaint suitable for publication in the *Federal Register* in accordance with the specifications in § 385.203(d) of this part. The form of notice shall be on electronic media as specified by the Secretary.

A form of notice suitable for publication in the *Federal Register* is attached to this Complaint as Attachment B.

10. Any person filing a complaint must serve a copy of the complaint on the respondent, affected regulatory agencies, and others the complainant reasonably knows may be expected to be affected by the complaint. Service must be simultaneous with filing at the Commission for respondents. Simultaneous or overnight service is permissible for other affected entities. Simultaneous service can be accomplished by electronic mail in accordance with § 385.2010(f)(3), facsimile, express delivery, or messenger.

A copy of this Complaint has been served on the following via email:

Timothy Caister
Vice President, Legal and Federal Affairs
Midcontinent Independent System Operator, Inc.
720 City Center Drive
Carmel, IN 46032
Telephone: 317-220-2166
Fax: 317-249-5912
Email: misolegal@misoenergy.org

Jacob Krouse
Deputy General Counsel – Regulatory
Midcontinent Independent System Operator, Inc.
720 City Center Drive
Carmel, IN 46032
Telephone: 317-408-7401
Fax: 317-249-5912
Email: jkrouse@misoenergy.org

Michael Kessler
Managing Assistant General Counsel
Midcontinent Independent System Operator, Inc.
720 City Center Drive
Carmel, IN 46032
Telephone: 317-249-5400
Email: mkessler@misoenergy.com

VIII. CORRESPONDENCE AND COMMUNICATIONS

All correspondence and communications regarding this Complaint should be addressed to the following persons:[68]

Heather Watts
Vice President and Associate General Counsel, Regulatory Services Indiana/Ohio
CenterPoint Energy
211 NW Riverside Drive
Evansville, IN 47708
(812) 491-5119
heather.watts@centerpointenergy.com

William R. Derasmo
Donna M. Byrne
Jacqueline M. Triggs
TROUTMAN PEPPER LOCKE LLP
401 9th Street, NW, Suite 1000
Washington, DC 20004
(202) 274-2886
william.derasmo@troutman.com
donna.byrne@troutman.com
jacqueline.triggs@troutman.com

IX. CONCLUSION

For the reasons discussed above, SIGE respectfully requests that the Commission swiftly issue an order granting the Complaint.

Respectfully submitted,

/s/ Heather Watts
Heather Watts
Vice President and Associate General Counsel, Regulatory Services Indiana/ Ohio
CenterPoint Energy
211 NW Riverside Drive
Evansville, IN 47708
(812) 491-5119
heather.watts@centerpointenergy.com

/s/ William R. Derasmo
William R. Derasmo
Donna M. Byrne
Jacqueline M. Triggs
TROUTMAN PEPPER LOCKE LLP
401 9th Street, NW, Suite 1000
Washington, DC 20004
(202) 274-2886
william.derasmo@troutman.com
donna.byrne@troutman.com
jacqueline.triggs@troutman.com

Counsel to Southern Indiana Gas and Electric Company

---

[68] To the extent necessary, SIGE respectfully requests waiver of Rule 203(b)(3) of the Commission's Rules of Practice and Procedure to permit all of the following representatives to be placed on the official service list for this proceeding.

Filed January 5, 2026

Attachment A

Cost Recovery Mechanism

SCHEDULE {XYZ}

Allocation of Costs Associated with Continued Availability of Unit 2 of F.B. Culley Generation Station
Pursuant to DOE Order No. 202-25-13

On December 23, 2025, the U.S. Secretary of Energy ("Secretary") issued an order pursuant to 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), determining that an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes ("202(c) Emergency"). *See* Department of Energy, Order No. 202-25-13 ("DOE Order"). The DOE Order compelled MISO and Southern Indiana Gas and Electric Company ("SIGE") to ensure the continued operation and availability the 103.7 MW Unit 2 of the F.B. Culley Generating Station coal-fired power plant ("Culley Unit 2") from December 23, 2025, through March 23, 2026, as such time may be extended by subsequent order of the Secretary (the "Order Duration Period").

The Secretary ordered MISO and SIGE to take all measures necessary to ensure that the Culley Unit 2 is available to operate during the Order Duration Period. The DOE Order also orders MISO to "take every step to employ economic dispatch of Culley Unit 2 to minimize cost to ratepayers." The DOE Order confirms that rate recovery is available pursuant to FPA section 202(c).

Costs associated with the DOE Order have been incurred, and will continue to be incurred, during the Order Duration Period ("Order Costs"). SIGE shall petition FERC to approve recovery of Order Costs, net of market revenues, that FERC determines are recoverable pursuant to section 202(c) ("Recoverable Order Costs").

This Schedule {XYZ} shall allocate the Recoverable Order Costs incurred during the Order Duration Period, and any extensions of the same or subsequent orders by the Secretary, in the following manner. MISO shall allocate the Recoverable Order Costs to LSEs in the Zones 1-7 (or such successor zone designations reflecting the Northern and Central MISO Zones) ("Affected LSEs") on a load ratio share basis.

The charge to each Affected LSE (AFF_LSE_CHG) is obtained by multiplying Affected LSE load ratio share (AFF_LSE_SHARE) by the Recoverable Order Costs (REC_ EMERG_ORDER_COSTS):

AFF_LSE_CHG = AFF_LSE_SHARE × REC_ EMERG_ ORDER_COSTS

Effective On: {DATE}

Attachment B

Form of Notice

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Southern Indiana Gas and Electric Company	)	
	)	Docket No. EL26-___-000
v.	)	
	)	
Midcontinent Independent System Operator, Inc.	)	

NOTICE OF COMPLAINT

(______________)

Take notice that on January 5, 2025, Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South ("SIGE") filed a complaint ("Complaint") against Midcontinent Independent System Operator, Inc. ("MISO") pursuant to sections 202(c), 306, and 309 of the Federal Power Act ("FPA")[1] and Rule 206 of the Federal Energy Regulatory Commission's ("FERC" or "Commission") Rules of Practice and Procedure.[2] SIGE requests the Commission direct MISO to revise its Open Access Transmission, Energy and Operating Reserve Markets Tariff to effectuate an emergency order issued by the Secretary of Energy on May 23, 2025, pursuant to FPA section 202(c).[3]

SIGE certifies that a copy of the Complaint was served on representatives of MISO.

Any person desiring to intervene or protest this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 C.F.R. §§ 385.211 and 214). Protests will be considered by the Commission in determining the appropriate action to be taken but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. The Respondent's answer and all interventions or protests must be filed on or before the comment date. The Respondent's answer, motions to intervene, and protests must be served on the Complainant.

The Commission encourages electronic submission of protests and interventions in lieu of paper using the "eFiling" link at http://www.ferc.gov. Persons unable to file electronically should submit an original and five (5) copies of the protest to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426.

---

[1] 16 U.S.C. §§ 824e, 825e, 825h (2024).

[2] 18 C.F.R. § 385.206 (2025).

[3] U.S. Department of Energy, Order No. 202-25-13 (December 23, 2025) ("DOE Order").

This filing is accessible online at http://www.ferc.gov, using the "eLibrary" link and is available for review in the Commission's Public Reference Room in Washington, DC. There is an "eSubscription" link on the website that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please email FERCOnlineSupport@ferc.gov, or call (866) 208-3676 (toll-free). For TTY, call (202) 502-8659.

Comment Date: 5:00 pm Eastern Time on (_______________).

Debbie-Anne A. Reese
Secretary

Attachment C

DOE Order 202-25-13

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

---

[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

[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.

[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
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 157
MISO Comments to FERC

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Northern Indiana Public Service Company LLC	)	
	)	**Docket No. EL26-36-000**
v.	)	
	)	
Midcontinent Independent System Operator, Inc.	)	

ANSWER OF THE
MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC.

The Midcontinent Independent System Operator, Inc. ("MISO" or "Respondent") submits[1] this Answer to the Complaint of Northern Indiana Public Service Company LLC ("NIPSCO" or "Complainant"). NIPSCO filed the Complaint in response to an order ("DOE Order") issued by the U.S. Secretary of Energy pursuant to Federal Power Act ("FPA") section 202(c) and section 301(b) of the Department of Energy Authorization Act.[2] The DOE Order determined "that an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes."[3] To address that emergency, the DOE Order directs MISO and NIPSCO to take all measures necessary to ensure the that R.M. Schahfer Generating Station's ("Schahfer") two coal-fired units, Units 17 and 18 ("Schahfer Units"), located in Wheatfield, Indiana, are available to operate.[4] NIPSCO's Complaint requests that MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff

---

[1] *See* Rules 206 and 213 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("FERC" or "Commission"), 18 C.F.R. § 385.206(f) (2025); 18 C.F.R. § 385.213 (2025).

[2] U.S. Department of Energy, Order No. 202-25-12, at 1 (December 23, 2025) ("DOE Order").

[3] DOE Order at 1.

[4] DOE Order at 1, 5.

("Tariff") be revised to permit recovery of costs incurred incident to the DOE Order and provides draft Tariff language for the Commission's review.

As recognized by the DOE in its May 23, 2025, 202(c) emergency order, MISO's Planning Resource Auction for the 2025-2026 Planning Year demonstrated sufficient capacity in the MISO Region.[5] While MISO does not intend to contest, within the context of this docket, the characterization within the Order that an emergency exists "due to a shortage of electric energy . . . [or] a shortage of facilities," it is important to recognize existing processes have cleared sufficient electric generating capacity across MISO for the periods of time covered by the Order. The clearing of sufficient capacity to meet anticipated demand across the MISO Region for the 2025-2026 Planning Year reflects the diligent efforts of MISO's members, Market Participants, Relevant Electric Retail Regulatory Authorities ("RERRA") and the Federal Energy Regulatory Commission ("FERC") to establish policies and processes that address both immediate and future capacity requirements. MISO continues to work with these parties in the context of anticipated growing demand for electricity, planned electric generating facility retirements, and an evolving mix of new electric generating resources to refine processes that address the challenges ahead. MISO is confident that these collaborative efforts do not require further intervention and will help ensure the region continues to procure sufficient capacity to meet demand.

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

[5] U.S. Department of Energy, Order No. 202-25-3, at 2 (May 23, 2025) ("May DOE Order").

[6] DOE Order at 5.

[7] DOE Order at 5.

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

I. Background

The Secretary of Energy issued the DOE Order on December 23, 2025.[8] The DOE Order identifies an "emergency situation" in the MISO region due to MISO's "year-round resource adequacy concerns,"[9] citing MISO's 2022 filing to revise its resource adequacy construct, MISO's 2023 Attributes Roadmap, MISO's 2024 report titled "MISO's Response to the Reliability Imperative," the North American Electric Reliability Corporation's ("NERC") 2024 Long-Term Reliability Assessment ("LTRA"), MISO's report of its 2025-2026 Planning Resource Auction ("PRA"), and the Organization of MISO States ("OMS") and MISO's 2025 survey results.[10] DOE additionally cites to executive orders issued by President Donald J. Trump on January 20, 2025 and April 8, 2025 as further evidence of "the dire energy challenges facing the Nation due to growing resource adequacy concerns"[11] and to a DOE Resource Adequacy Report, issued in July 2025, that "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.'"[12] The DOE Order notes that the Schahfer Units were scheduled to cease operations in December 2025, and determines that the continued operation of the Units "will

[8] DOE Order at 6.

[9] DOE Order at 1.

[10] DOE Order at 1-3.

[11] DOE Order 3-4.

[12] DOE Order at 4.

best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity."[13]

The DOE Order directs MISO and NIPSCO to "take all measures necessary to ensure that Schahfer Units 17 and 18 are available to operate."[14] MISO is "directed to take every step to employ economic dispatch of Schahfer Units 17 and 18 to minimize cost to ratepayers" and "to provide the [DOE] … with information concerning the measures it has taken and is planning to take to ensure the operational availability of Schahfer Units 17 and 18 consistent with this Order."[15] MISO notes that it is working closely with NIPSCO to ensure that the Schahfer Units are available to operate in compliance with the DOE Order. The DOE Order states that, "NIPSCO is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers to effectuate this Order."[16] The Order states, "[r]ate recovery is available pursuant to 16 U.S.C. § 824a(c)."[17]

II. ANSWER

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

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

---

13 DOE Order at 1, 4.

14 DOE Order at 5.

15 DOE Order at 5.

16 DOE Order at 5.

17 DOE Order at 5.

18 Complaint at 18-19.

DOE Order.[19] As discussed below, MISO does not oppose the addition of a cost recovery schedule to its Tariff that would allow NIPSCO to recover its costs as contemplated by the DOE Order.

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

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

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

MISO reserves the right to modify, adjust, or otherwise change the cost recovery allocation formula proposed by NIPSCO, should it be necessary, to account for existing Tariff requirements and to include other clarifications as may be appropriate.[20]

III. ADMISSIONS AND DENIALS; AFFIRMATIVE DEFENSES

MISO denies all allegations in the Complaint not specifically and expressly admitted herein.[21]

IV. COMMUNICATIONS

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

Jacob Krouse*
Deputy General Counsel – Regulatory
Michael Kessler
Managing Assistant General Counsel

James C. Holsclaw*
Taylor M. Carpenter
Calfee, Halter & Griswold, LLP
3900 Salesforce Tower

---

19 In response to the May DOE Order, MISO added Schedule 55 to its Tarriff to provide a cost recovery mechanism for Consumers Energy Company; Schedule 55 only provides a cost recovery mechanism for Consumers Energy Company, therefore additional schedules are needed to provide cost recovery mechanisms for NIPSCO and other effected facilities.

20 The issue of whether to allocate costs on a demand or energy basis is pending before the Commission in Docket No. EL25-90-000. The Commission's decision in that docket may necessitate additional Tarriff changes to the proposed cost recovery mechanism at issue here.

21 18 C.F.R. § 385.213(c)(2)(i)-(ii) (2025).

Midcontinent Independent
System Operator, Inc.
720 City Center Drive
Carmel, Indiana 46032
Telephone: (317) 249-5400
jkrouse@misoenergy.org
mkessler@misoenergy.org

111 Monument Circle
Indianapolis, Indiana 46204
Telephone: (317) 308-4266
jholsclaw@calfee.com
tcarpenter@calfee.com

V. CONCLUSION

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

Respectfully submitted,

/s/ Michael Kessler

Michael Kessler
Managing Assistant General Counsel
Midcontinent Independent
System Operator, Inc.
720 City Center Drive
Carmel, IN 46032
Telephone: (317) 249-5400
mkessler@misoenergy.org

James C. Holsclaw
Taylor M. Carpenter
Calfee, Halter & Griswold, LLP
3900 Salesforce Tower
111 Monument Circle
Indianapolis, IN 46204
Telephone: (317) 308-4266
jholsclaw@calfee.com
tcarpenter@calfee.com

*Counsel for Midcontinent Independent
System Operator, Inc.*

CERTIFICATE OF SERVICE

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

Dated this 20th day of January, 2026 in Carmel, Indiana.

/s/ Julie Bunn

Julie Bunn
Midcontinent Independent
System Operator, Inc.
720 City Center Drive
Carmel, IN 46032
317-249-5400

Document Content(s)