ORIGINAL

Commissioner	Yes	No	Not Participating
Huston	√		
Freeman	√		
Krevda	√		
Veleta	√		
Ziegner	√		

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

APPLICATION OF DUKE ENERGY INDIANA, LLC FOR APPROVAL OF A CHANGE IN ITS FUEL COST ADJUSTMENT FOR ELECTRIC SERVICE AND FOR APPROVAL OF A CHANGE IN ITS FUEL COST ADJUSTMENT FOR HIGH PRESSURE STEAM SERVICE, IN ACCORDANCE WITH INDIANA CODE §8-1-2-42, INDIANA CODE §8-1-2-42.3, AND VARIOUS ORDERS OF THE INDIANA UTILITY REGULATORY COMMISSION

CAUSE NO. 38707 FAC 133

APPROVED: SEPT 28 2022

ORDER OF THE COMMISSION

Presiding Officers:
David E. Ziegner, Commissioner
David E. Veleta, Commissioner
Loraine L. Seyfried, Chief Administrative Law Judge

On July 28, 2022, Duke Energy Indiana, LLC ("Applicant") filed its Verified Application and direct testimony and exhibits for approval by the Indiana Utility Regulatory Commission ("Commission") of a change in its fuel adjustment charge ("FAC") to be applicable during the billing cycles of October, November, and December 2022 for electric and steam service. On July 29, 2022, Duke Energy Indiana Industrial Group ("Industrial Group") filed its Petition to intervene in this proceeding, with a subsequent amendment on August 18, 2022. On August 2, 2022, Nucor Steel-Indiana, a division of Nucor Corporation ("Nucor"), filed its Petition to intervene in this proceeding. The Presiding Officers granted the Petition to Intervene of the Industrial Group on August 10, 2022, and the Petition to Intervene of Nucor on August 11, 2022. On August 9, 2022, Applicant notified the Commission that Mr. Shawn D. Shultz would adopt the case-in-chief testimony of Mr. Brett Phipps.

On September 1, 2022, the Indiana Office of Utility Consumer Counselor ("OUCC") filed its audit report and testimony, and Industrial Group also filed its testimony. On September 7, 2022, Applicant filed a revision to the direct testimony of Mr. Shultz. Applicant filed its rebuttal testimony on September 9, 2022, and advised Mr. James J. McClay, III was adopting the case-in-chief testimony of Mr. Wenbin (Michael) Chen.

A public evidentiary hearing was held in this Cause on September 19, 2022, at 1:30 p.m. in Room 222 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. Applicant, Nucor, Industrial Group, and the OUCC appeared at the hearing by counsel. Applicant, the OUCC and Industrial Group offered their respective prefiled testimony and exhibits into the evidentiary record without objection. The Industrial Group cross-examined Applicant's witness J. Bradley Daniel.

Based upon the applicable law and the evidence herein, the Commission now finds:

1. **Notice and Commission Jurisdiction.** Notice of the hearing in this Cause was given as required by law. Applicant is a public utility within the meaning of Ind. Code § 8-1-2-1(a). Under Ind. Code § 8-1-2-42, the Commission has jurisdiction over changes to Applicant's rates and charges related to adjustments in fuel costs. Therefore, the Commission has jurisdiction over the parties and the subject matter of this Cause.

2. **Applicant's Characteristics.** Applicant is a public utility corporation organized and existing under the laws of the State of Indiana with its principal office in Plainfield, Indiana. Applicant is engaged in rendering electric utility service in the State of Indiana and owns, operates, manages, and controls, among other things, plant and equipment within the State of Indiana used for the production, transmission, delivery and furnishing of such service to the public. Applicant also renders steam service to customer International Paper.

3. **Available Data on Actual Fuel Costs and Authorized Jurisdictional Net Income.** On June 29, 2020, the Commission issued an Order in Cause No. 45253 ("June 29 Order") approving base retail electric rates and charges for Applicant. The Commission's June 29 Order found that Applicant's base cost of fuel should be 26.955 mills per kWh and that Applicant's base rates for electric utility service should reflect an authorized jurisdictional operating income level of $584,678,000 prior to the Step 1 and Step 2 adjustments and for impacts of investments remaining in two riders.

Applicant's cost of fuel to generate electricity and the cost of fuel included in the net cost of purchased electricity for the month of May 2022, based on the latest data known to Applicant at the time of filing after excluding prior period costs, hedging, and miscellaneous fuel adjustments, if applicable, was $0.060221 per kWh as shown on Applicant's Attachment A, Schedule 9. In accordance with previous Commission Orders, Applicant calculated its phased-in authorized jurisdictional net operating income level for the 12-month period ending May 31, 2022, to be $579,205,000 (*see* Applicant's Ex. 6-B, p. 3). No evidence was offered objecting to the calculation of the authorized jurisdictional net operating income level proposed by Applicant, and we find it to be proper.

4. **Fuel Purchases.** Mr. Shawn D. Shultz testified regarding Applicant's coal procurement practices and its coal inventories. Mr. Shultz testified that as of May 31, 2022, coal inventories were approximately 1,961,923 tons (or 38 days of coal supply), which is an increase over inventories reported in Cause No. 38707 FAC 132 ("FAC 132"). Mr. Shultz reported that the increase can be attributed to the price adjustment discussed by Mr. J. Bradley Daniel and weather driven demand throughout the FAC period. He testified that Applicant continues to evaluate a host of options to effectively manage its coal inventory. He further testified that additional inventory mitigation efforts, aside from the price adjustment, include contracting for onsite third-party train operations to alleviate railroad labor constraints, spot purchases to create diversity and better routes, adding truck deliveries where logistically feasible, and adjusting shipping schedules to ensure deliveries where most needed. Mr. Shultz stated that in cases where actual burns unexpectedly drop below projections and inventory levels are above target, as inventory levels dictate, Applicant explores options to store or defer contract coal or resell surplus coal into the market. In cases where actual burns unexpectedly increase above projections, Applicant accelerates purchases of supply and looks for operational efficiencies. Due to current coal market conditions, purchase opportunities will continue to be difficult in the near term.

Mr. Shultz testified that spot natural gas prices are dynamic, volatile, and can change significantly day to day based on market fundamental drivers. During the three-month period from March through May 2022, the price Applicant paid for delivered natural gas at its gas burning stations was between $4.09 per million BTU and $9.38 per million BTU. He testified natural gas prices for the period were above those experienced in the FAC 132 review period. Mr. Shultz testified that, in his opinion, Applicant purchased natural gas at the lowest cost reasonably possible.

The OUCC's witness, Mr. Michael D. Eckert, testified that Applicant is actively trying to manage its coal purchases and inventory. Although additional coal has been secured for 2022-2023, Applicant is struggling to acquire and maintain adequate transportation of coal to its stations. He testified that while Applicant is attempting to increase train deliveries, it has not filed a complaint with the Service Transportation Board ("STB") or enforced any non-compliance options in its rail contracts. OUCC witness Mr. Guerrettaz testified Applicant diverted coal from Edwardsport to Cayuga until March 21, 2022, and used a 74/26% mix of coal versus natural gas in April and May. He noted that having Edwardsport use natural gas for generation cost Applicant three times more than coal per MWh. Mr. Eckert recommended Applicant continue to update the Commission on its coal inventory and 2022 projected coal burn and coal purchases, as well as how Applicant is addressing its coal transportation issues.

The Industrial Group's witness, Mr. Michael P. Gorman, testified that Applicant has not made reasonable efforts to provide fuel at the lowest possible price. Mr. Gorman noted that Applicant seeks approval to recover from ratepayers its cost of fuel and purchased power that displaced coal generation. He also noted that Applicant has recognized the importance of coal inventory for the reliable operation of its system.

In discussing Applicant's energy generation, Mr. Gorman testified that over 84% of Applicant's total energy is generated from burning or gasifying coal. Further, he testified that Applicant is responsible for contracting adequate coal supply to provide the fuel for reliable generation and also for contracting adequate transportation to move the coal to its generation sites. Mr. Gorman stated that if Applicant is unable to procure adequate transportation, it must rely heavily on other options that are more expensive. In doing so, Applicant also risks reducing the reliability of its service.

Applicant has two coal plants which have been affected by reduced coal inventories: Gibson Units 1-5 and Cayuga Units 1-2. Mr. Gorman testified that Applicant determined its coal inventory constraints at Gibson and Cayuga, dating back to August 2021 and October 2021, respectively, could impact operation of its system. He also noted Applicant's fuel forecast model reflects the continued use of a supply offer adjustment from October 2022 through December 2022 periods included in the current FAC.

Mr. Gorman further testified that the costs of both the Gibson and the Cayuga units are recovered from ratepayers in base rates despite Applicant's customers not receiving the full benefits of the units because they are not often used due to the price adjustment. Applicant's heavy reliance on coal and the problems with the coal supply delivery chain have presented significant issues regarding reliability and cost. As such, Mr. Gorman stated, the lack of access to coal inventory prevents Applicant's coal-fired generation assets from being used as a hedge against high purchased power costs. Mr. Gorman testified that it is not fair for ratepayers to pay for both increased purchased power and coal plants that are operating at reduced levels in base rates. Mr. Gorman noted that there has been a massive increase in Applicant's FAC charge since the beginning of 2022.

Further, Mr. Gorman noted that Applicant has not demonstrated that it has made reasonable efforts to provide fuel at the lowest possible price. Mr. Gorman stated that despite having an obligation to maintain its coal inventories so that the units can run for the benefit of its customers, Applicant has demonstrated imprudent management decisions of its coal inventory and coal supply agreements. Mr. Gorman noted that other facts indicated Applicant's imprudent management of its fuel costs. First, he explained that Applicant should have executed hedge agreements to mitigate increase in its FAC via purchases of natural gas hedges and/or Midcontinent Independent System Operator, Inc. ("MISO") energy purchases to be used in lieu of operation of its coal units. In support of this assertion, Mr. Gorman testified that from August to October 2021, natural gas prices ranged from $3.70 to a little more than $5.00. He noted that the ability to hedge these prices lower than the actual spot market prices would translate into MISO energy purchases because of the correlation between forward gas prices and forward MISO energy prices.

Next, Mr. Gorman turned to a discussion of coal supply agreements. He noted that Applicant does have firm contracts for delivery of coal, but none of Applicant's carriers are in breach of their agreements. When asked why Applicant cannot get adequate coal to its facilities in light of the firm agreements, Mr. Gorman testified that the contract minimums that Applicant negotiated were too low to sufficiently maintain Applicant's coal inventories at an adequate level. Despite this, Applicant extended several of the contracts in December 2021 or January 2022 with no apparent changes to increase the amount of firm delivery.

Mr. Gorman then focused on the Edwardsport fuel choice. He expressed concern that Applicant had not demonstrated that it adequately evaluated continuing to run Edwardsport on natural gas instead of coal despite the ability to run Edwardsport on either natural gas or coal. For a period of time, Mr. Gorman explained, Applicant ran Edwardsport partially on natural gas and diverted some coal that would otherwise serve Edwardsport to Applicant's other coal generating facilities. Mr. Gorman noted that Applicant ceased partial natural gas operation as of March 21, 2022.

Mr. Gorman explained, in discovery, Applicant indicated that it did not pursue continuing to operate Edwardsport on natural gas because it did not view this option as economic due to the higher cost of natural gas. However, Mr. Gorman pointed out that Applicant has failed to adequately support this position. First, Applicant indicated in discovery that it was unable to determine the costs of operating Edwardsport wholly or partially on natural gas. Second, Applicant admitted in discovery that it did not calculate the cost of the supply offer adjustment to Cayuga (which can accept diverted Edwardsport coal). Yet because the lack of coal is driving the need for the adjustment, which increases Applicant's reliance on market purchases, the effect of the cost of the supply offer is relevant to evaluating the economics of running Edwardsport on natural gas. If Edwardsport were not using coal, then Applicant could reduce its reliance on the coal supply offer adjustment, Mr. Gorman pointed out. Third, Mr. Gorman asserted that other benefits of running on natural gas should be considered as well, such as the fact that operating on natural gas can enable Edwardsport to respond more quickly to changes in market prices. When operating on natural gas is uneconomic, Edwardsport can more quickly be shut down. In contrast, when Edwardsport is run on coal, it is offered as a must-run unit—even during periods of time when operating on coal is uneconomic.

In rebuttal, Mr. Shawn Shultz testified Mr. Gorman's assertion that Applicant was imprudent with its coal inventory management decisions is inaccurate. Applicant began implementing mitigation measures in 2021 when it began experiencing reduced coal inventories due to high natural gas and power prices, and significantly constrained rail deliveries. In the fall of 2021, Cayuga's inventory remained flat at the minimum acceptable inventory level with no opportunity to build going into the winter. To continue to meet coal supply needs, Applicant successfully conducted two spot solicitations for coal in July and August, as well as a long-term solicitation in September 2021 to ensure increased diversity of supply for winter 2022, and to meet projected needs in 2022 and 2023. The solicitations were successful in securing two additional suppliers and adding an additional delivery source with an existing supplier. As a result of the September solicitation, two additional supply commitments were secured along with additional tonnage from current suppliers through 2024. Applicant also diversified its transportation options by trucking coal to Cayuga and Gibson. Mr. Shultz testified Applicant began pursuing supplemental truck deliveries to Cayuga in early October, but due to several challenges to be addressed, including the volume of trucks needed, limited availability of drivers and trucks in a tight labor market, and the need to implement safety measures at both the mines and Cayuga, the trucking agreement took a while to negotiate and finalize. The agreement was executed on November 30, 2021, with deliveries beginning less than a week later. Applicant expanded its supplemental truck deliveries to include direct deliveries to Gibson starting the first week of April 2022.

Mr. Shultz testified that he disagrees with Mr. Gorman's assertion that Applicant failed to negotiate contracts for firm delivery of coal, stating that Mr. Gorman has a fundamental misunderstanding of the structure of Applicant's rail agreements. Mr. Shultz explained that the "firm" contracts obligate Applicant to take firm minimum volume commitments from the rail provider in exchange for more favorable pricing for customers than the railroads' tariff rates. This guarantees Applicant has rail transportation in place at a more favorable rate and the ability to transport coal from the supplier to its generating stations. However, the rail agreements do not contain firm "contract minimums" that obligate the rail provider to ship a minimum volume or otherwise guarantee delivery performance. It is within the discretion of the railroads to determine how to operate their systems. The rail transportation contracts do not contain provisions for non-performance by the railroads nor is it common practice for the railroads to amend the performance language. Despite these conditions, and being captive to specific rail providers, Applicant, during its negotiations, regularly discusses opportunities to include performance language in its rail contracts, but the railroads have been unwilling to negotiate on this point. Applicant has actively requested improved performance from its rail transportation providers, including how it could incentivize better performance. Mr. Shultz testified Applicant was proactively communicating with its rail transportation providers for improved rail performance prior to complaints being filed with the STB. Applicant did not file its own complaint with STB, but instead participated through its membership in the National Coal Transportation Association ("NCTA"). Additionally, Applicant maintained pressure on the rail providers through frequent direct communications. He testified the STB issued a decision on May 5, 2022, ordering service recovery plans and progress reports from the four largest U.S. rail carriers and directing those carriers to participate in biweekly conference calls to further explain efforts to correct service deficiencies. It is also requiring all Class I rail carriers to report more comprehensive and customer-centric performance metrics and employment data for a six-month period. As a member of NCTA and a party to their comments, actions from the STB will be applicable to Applicant. Mr. Shultz testified that regardless of the STB process, Applicant is continuing to work with its rail providers to promote increased performance and will continue to provide updates in subsequent FAC proceedings and during the OUCC audit process.

Mr. Shultz testified the decision to operate Edwardsport on approximately half natural gas and half gasified coal provided flexibility to allocate deliveries of coal between Edwardsport and Cayuga to ensure a reliable fuel supply for the projected total coal burns at Cayuga Units 1 and 2. Applicant's witness Mr. Daniel testified in rebuttal that although Applicant allocated deliveries from Edwardsport to Cayuga to help ensure a reliable fuel supply at Cayuga through the winter of 2022, further allocations were not necessary as Cayuga station was able to build inventory to reliable levels throughout the FAC period without allocating deliveries from Edwardsport. He also testified that the flexibility to allocate coal deliveries from Edwardsport to Gibson station does not exist because only Norfolk Southern railroad accesses Gibson station. Therefore, because there is limited benefit to Cayuga station, and no benefit in the case of Gibson, of allocating coal deliveries from Edwardsport, it is inaccurate that Applicant could reduce its reliance on the coal supply offer adjustment to the benefit of customers if Edwardsport was run on natural gas instead of coal. Mr. Daniel testified that because Edwardsport can operate without an offer adjustment, operating the station on coal remains the most economic solution for customers. As gas prices have increased throughout the FAC period and into the summer, the benefit and prudence of running Edwardsport on natural gas has decreased even further.

Mr. Daniel testified that several factors must be evaluated over time to determine the primary fuel with which to operate Edwardsport station, including the price of natural gas compared to the price of coal, availability and transport of natural gas to run the plant solely on natural gas, the increase in Nitrogen Oxide ("NOx") emission rate on natural gas versus syngas, and unit megawatt capability on natural gas versus coal. Consideration of these key economic factors during the FAC period indicates that operating the unit on coal is substantially more economically beneficial to customers than operating on natural gas. He testified that consideration must also be given to the fact that the station's gasifiers and other gasification systems have an approximate 14-day cycle time which impacts the ability of the station to respond to a volatile natural gas price environment. Cycling on and off syngas could also negatively impact the station's equivalent forced outage rate, impacting Edwardsport's energy value in the market, as well as future capacity value. The station's permits also have to be taken into consideration, as Edwardsport is permitted by the Indiana Department of Environmental Management to operate on coal as a primary fuel instead of natural gas. Mr. Daniel testified that Applicant has made reasonable efforts to provide fuel at the lowest possible price and at the lowest fuel cost reasonably possible, using the most cost-efficient resources available.

Mr. Daniel testified that Applicant continues to submit an incremental cost offer for its share of Benton County Wind Farm in accordance with the settlement agreement with Benton County Wind Farm discussed in FAC 113.

Mr. Gorman took issue with the terms of Applicant's transportation contracts. However, Mr. Schultz's testimony provides evidence that Applicant employed available contracting options when negotiating transportation contracts. Applicant's Ex. 7, pp. 9-10. Therefore, based on the evidence presented, we find that Applicant made every reasonable effort to acquire fuel for its own generation or to purchase power so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible during March through May 2022. With regard to its coal inventory levels and transportation issues, Applicant will provide an update on the status in its next FAC proceeding as recommended by the OUCC.

5. Hedging Activities. Applicant's witness Mr. Wenbin (Michael) Chen testified Applicant takes advantage of the hedging tools available to protect against natural gas price fluctuations. Mr. Chen testified that Applicant realized a gain of $4,104,979 from natural gas hedges purchased for March through May 2022. He testified that market price for gas realized higher values than the hedged prices attributable to strong price increases triggered by the Russian invasion of Ukraine. He testified Applicant experienced net realized power hedging gains for the period of $12,331,438 primarily attributable to geopolitical concern in Europe, as well as continued disruptions in coal supply. Ms. Suzanne E. Sieferman testified that Applicant realized a total net hedging gain of $16,424,598 during the period for all native gas and power hedging activities other than the MISO virtual energy market participation (including prior period adjustments).

Mr. Chen explained that, consistent with the Commission's June 25, 2008 Order in Cause No. 38707 FAC 68 S1 ("FAC 68 S1 Order"), beginning on August 1, 2008, Applicant has not utilized its flat hedging methodology. Rather, Applicant will hedge up to approximately flat minus 150 MW on a forward, monthly and intra-month basis, and up to approximately flat on a Day Ahead/Real-Time basis. This methodology will leave Applicant with at least 150 MW of expected load unhedged on a forward forecasted basis. Mr. Chen opined Applicant's gas and power hedging practices are reasonable. He stated Applicant never speculates on future prices and that its hedging practice is economic at the time the decision is made and reduces volatility because Applicant is transacting in a less volatile forward market, as opposed to more volatile spot markets.

Mr. Eckert testified that Applicant's hedging gains and losses for the period December 2013 through January 2021 were relatively consistent. He testified beginning in February 2021 and, with the exception of March 2021, Applicant experienced large hedging gains through November 2021. Then Applicant experienced large hedging losses starting in December 2021 through February 2022. In the current FAC period, Applicant experienced a small loss in March and gains in April and May. Mr. Eckert recommended Applicant file testimony in its next FAC on the results of its informal hedging policy review. OUCC witness Mr. Gregory Guerrettaz further recommended Applicant document any significant change in Applicant's hedging position or policy.

Industrial Group witness, Mr. Gorman, testified that Applicant's hedging plan has resulted in increased volatility starting in FAC 128. Mr. Gorman testified that Applicant should make changes to its hedging strategy due to its low coal inventory and inability to use its coal generation as a hedge against price spikes in natural gas and purchased power. He reiterated that Applicant has also been reluctant to utilize the dual fuel capability of Edwardsport and noted that when

Applicant does use it, it only utilizes spot gas purchases. Mr. Gorman stated that Applicant should have modified its hedging plans when it became aware of the constraint on coal deliveries in August 2021. Applicant estimated at that time that the coal supply constraints would last through 2022. Further, he stated that Applicant should have considered longer term hedges for natural gas and purchase power, which would have been more cost effective and provided reduced price volatility to customers.

In rebuttal, James J. McClay, III testified that Applicant recognized the need for more gas and power hedges when coal deliveries started to become constrained in the fall of 2021. Applicant purchased both forward gas and power hedges by layering in hedge transactions and adjusting purchase amounts as the supply offer adjustment was updated. He testified that Mr. Gorman's suggestion that Applicant was imprudent in its hedging activities is not supported by the facts. Applicant's placement of hedges followed Applicant's internal rules and protocols were based on forecasted needs at the time and ultimately resulted in a gain for customers. Mr. McClay also disagreed with Mr. Gorman's suggestion that Applicant could have purchased MISO energy for lower cost due to a correlation between forward gas prices and forward MISO energy prices. Mr. McClay testified that this is not the point of a hedging program, and Applicant only considers hedging transactions when the model analytics demonstrate transactions are economic at the time. Applicant does not speculate on prices, as Mr. Gorman suggests it should. Applicant is mitigating price risk exposure for its committed load by entering into transactions that are economic given its energy position and that are projected to cap its energy price risk for the power hedged. Mr. Gorman's chart used for his forward gas price argument illustrates the volatility seen in gas prices and underscores the purpose of a hedging program, which cannot speculate on forward prices but instead is designed to achieve a balanced position. Mr. McClay testified that Applicant executes hedges when it is projected to be economically short, not simply when prices seem low. He testified that Applicant's hedging program or actual hedges placed have not resulted in increased volatility to customers, as suggested by Mr. Gorman. Instead, the larger swings in both gas and MISO prices have resulted in increased volatility to the profits and losses associated with those hedges. The hedges themselves served their purpose to limit customer exposure to actual market prices and mitigate fuel and power price volatility in uncertain markets. Both stronger power and gas prices and big weather swings in 2021 contributed to higher volatility in hedging results. Mr. McClay testified that Mr. Gorman has the benefit of perfect hindsight when he now judges Applicant for what it did or did not do in August 2021, while Applicant must make the best decisions it can based on the information it has at the time. In August 2021, Applicant did not know how long coal supply constraints would last, and began meeting weekly to assess the developing situation and determine an appropriate response. With coal deliveries uneven and future long-term coal supply and deliveries difficult to forecast, Applicant purchased more gas and power hedges than usual for the near months where impact of coal conservation measures was more certain. Applicant also adapted its hedging to buy for the spring 2022 outage season. Mr. McClay testified Applicant is willing to meet with the OUCC and its industrial customers to discuss any going forward changes to its hedging program.

Applicant presented evidence that its power hedging practices relevant to this proceeding were consistent with the Agreement previously approved in the FAC 68 S1 Order (*see* Applicant's Ex. 3, p. 10). Thus, we allow Applicant to include $16,424,598 of net gains from native gas and power hedges in the calculation of fuel costs in this proceeding.

Regarding Mr. Gorman's criticism of Applicant's hedging plan and request that the Commission open a subdocket, Applicant's witness McClay noted that Applicant is open to reviewing their hedging program. Further, McClay stated that "[p]rior to proposing any changes to our hedging program, Applicant will offer to meet with the OUCC, the Commission Staff, and our industrial customers to discuss the price volatility risks we face, the price risk tolerances of our customers, and the appropriate objectives for Applicant's hedging strategy." Applicant's Ex. 9, p. 8. In Cause No. 38707 FAC 68 S1, the Commission ordered the parties in that proceeding to hold annual discussions regarding hedging methodology and parameters and prospective hedging plans, which in turn led to a relatively long period of hedging clarity in Applicant's FAC proceedings. Applicant's FAC proceedings would again benefit from further discussions among the parties in this Cause. Therefore, the Industrial Group's request for a subdocket is denied, and instead, the parties are instructed to meet to discuss possible changes to Applicant's hedging plan within 60 days of this Order. Further, Applicant should update the Commission on the status of this collaborative process in future FAC proceedings.

6. <u>Participation in the Energy and ASM Markets and MISO-Directed Dispatch</u>. On June 1, 2005, the Commission issued an Order in Cause No. 42685 ("June 1 Order"), in which we approved certain changes in the operations of the investor-owned Indiana electric public utilities that are participating members of MISO. In this proceeding, Mr. Daniel testified that Applicant included Energy Markets charges and credits incurred as a cost of reliably meeting the power needs of Applicant's load, including: (1) Energy Markets charges and credits associated with Applicant's own generation and bilateral purchases that were used to serve retail load; (2) purchases from MISO at the full locational marginal pricing at Applicant's load zone; (3) other Energy Markets charges and credits included in the list on page 37 of the June 1 Order; (4) credits and charges related to auction revenue rights and Schedule 27 and Schedule 27-A; and (5) fuel related charges and credits received from PJM Interconnection LLC from the operation of Madison Generation Station as approved in Cause No. 45253.

Mr. Daniel testified spot and future natural gas and power prices remained strong through the FAC 133 period, and coal burn projections remained strong as a result. These factors, combined with continued constraints in the coal supply and transportation market, continued the need for Applicant's adjustment to supply offers to MISO to maintain a reliable level of coal inventory at Gibson units 1-5 and Cayuga units 1-2. He testified that with continued commodity price strength and delivery constraints, Applicant continued to use supply offer adjustments to achieve targeted station inventory levels. In the current constrained environment, without a supply offer adjustment, Applicant's coal inventory would drop to low and unreliable levels. Mr. Daniel testified Applicant used its production cost model to determine the adjustment amount. The model utilizes up-to-date spot and future commodity and power prices, along with actual and targeted station coal inventory to run scenarios that produce the amount of adjustment needed to meet reliable inventory levels. He testified that modeling the offer adjustment to bound coal inventory levels between a minimum and maximum full load burn inventory at Gibson and Cayuga stations provides an economic and reliable balance of coal inventory management. He explained that the supply offers at Gibson units 1-5 and Cayuga units 1-2 are calculated just as they are normally, and then adjusted higher by the necessary $/MWh supply offer adjustment amount. Applicant is monitoring commodity prices and coal inventories within its normal course of business and is updating the offer adjustment on a weekly basis. Mr. Daniel testified the price adjustment is in the best interest of Applicant's customers and is working as intended. Pursuant to the Commission's Order in Cause No. 38707

FAC 130, Mr. Daniel presented support for the reasonableness of the supply offer adjustments during March through May 2022.

Mr. Daniel testified that Applicant allocated coal deliveries from Edwardsport to Cayuga to help meet winter inventory targets. Beginning December 17, 2021, Edwardsport operated on one gasifier and supplemented the station with natural gas which helped restore reliable coal inventory at Cayuga. Edwardsport returned to two gasifier operation on March 21, 2022. He testified the adjustment to economic offers at Wheatland CT continued through this FAC period, with 12-month rolling NOx tons emissions decreasing to 190.9 tons. Applicant expects some level of adjustment to its economic offers at Wheatland to continue through much of 2022.

OUCC witness Mr. Eckert testified the OUCC understands Applicant's need for the coal increment to maintain a reasonable level of coal inventory and meet reliability concerns in MISO. He recommended Applicant file testimony, schedules and workpapers to justify the need for, or use of, coal increment/decrement pricing in its next FAC proceeding. OUCC witness Mr. Gregory Guerrettaz testified that Applicant only considers whether to use or not use an adder in its analysis, and that if an adder was not implemented, its inventory automatically went to zero. He further testified that Applicant's minimum inventory amount is higher than MISO's requirement. For instance, PJM's policy requires it to be notified when inventory balances reach 10 days.

Industrial Group witness Mr. Gorman testified that Applicant has had to rely on increased purchased power to displace generation from its steam plants to meet its customers' load as a result of implementing a price adjustment to conserve coal inventory. This price adjustment, Mr. Gorman stated, affects the dispatch by the MISO. Mr. Gorman noted that this adjustment also makes Applicant's generation more expensive and less likely to be dispatched.

Mr. Gorman noted that the impact of the MISO price adjustments makes coal units more expensive to operate and in turn, MISO dispatches the units less. This results in Applicant having to buy power on the market that is more expensive to cover the shortfall in its coal generation output. Mr. Gorman referenced Applicant's statement that absent the use of a supply offer adjustment, coal consumption would likely exceed the amount of coal that can be delivered to its plants. Mr. Gorman noted that because of this, coal inventory constraints would likely continue to impact the cost of fuel in the FACs. Mr. Gorman cited the example of Applicant offering its other coal units into the MISO market using an adjustment to its supply offers that increases the cost of coal to reduce the frequency when Applicant's coal generating units will be called upon by MISO to run. Applicant indicated that the purpose of this adjustment was to preserve its coal supply, but the adjustment resulted in Applicant's increased reliance on market purchases. Mr. Gorman noted that if Edwardsport were not using coal, then Applicant could reduce its reliance on the coal supply offer adjustment. Mr. Gorman reiterated that Applicant has not evaluated the costs associated with the supply offer adjustment. But that because the lack of coal is the cause for the adjustment, the effect is also relevant to evaluating the economics of running Edwardsport on natural gas. He added that other benefits of using natural gas should also be considered. For example, Edwardsport would be able to respond more quickly to changes in market prices if it were run on natural gas. He discussed that when natural gas is uneconomic, Edwardsport can be quickly shut down. Conversely, if Edwardsport is run on coal, it is offered as a must-run unit even during periods when coal operation is uneconomic. Mr. Gorman concluded that Applicant's discovery responses did not demonstrate that it adequately evaluated these issues.

In rebuttal, Mr. Daniel testified that Applicant is willing to continue filing in future FAC proceedings testimony and a confidential exhibit providing justification for any actual need for, or use of, any coal increment/decrement pricing. However, he testified Applicant is unable to state with any level of certainty the increment's impact on the FAC factor, as such estimation comes with a host of limitations and complications requiring a myriad of assumptions. He further testified that there is no way to know how MISO would have committed or dispatched differently as there is no way to know whether an increment has direct impact on MISO Locational Marginal Prices. There is no way to assume MISO would have cleared or deployed ancillary services any differently. Further complicating such estimation is that other market participants are likely taking similar actions. Applicant also does not have access to MISO's optimization software and therefore cannot assess other market participant actions. Finally, this calculation would have to assume a future replacement market price for coal that was not consumed and not utilize the current weighted average or contract price of delivered coal.

Mr. Daniel testified that Mr. Guerrettaz' assessment of the adder analysis is not factually correct. If an adder was not implemented, based on up-to-date information, coal inventory would drop to unreliable levels and ultimately to zero. He also disagreed with Mr. Guerrettaz' assessment that Applicant is modeling too conservative of a minimum inventory for its analysis to justify the use of the adder. Mr. Daniel argued that Applicant uses the same minimum inventory target for planning and procurement purposes as it does in its modeling and analysis which provides economic and reliable balance of coal inventory management. He also said it would not be prudent to tie Applicant's inventory management to MISO (or PJM) inventory requirements because the minimum inventory notifications are emergency in nature. Mr. Daniel testified that planning and modeling to emergency status levels increases the risk of higher cost mitigations in the market, including de-committing generation units and increasing reliance on purchase power should coal inventories be drawn down to regional transmission operator emergency notification levels. Mr. Daniel testified that utilizing a price offer adjustment in the current constrained environment is in the best interest of Applicant's customers from a fuel security standpoint as well as an economic standpoint.

Applicant's witness Ms. Mary Ann Amburgey testified as to the procedures followed by Applicant to verify the accuracy of the charges and credits allocated by MISO and PJM to Applicant. She testified MISO began invoicing Applicant in December for the new Short-Term Reserve charge types. Ms. Amburgey also discussed the process by which MISO issues multiple settlement statements for each trading day and the dispute resolution process with respect to such statements. She stated that every daily settlement statement received by Applicant from MISO is reviewed utilizing the computer software tools described in her testimony. Ms. Amburgey testified that she is confident that the amounts paid by Applicant to MISO and PJM, net of any credits, are proper and that such amounts billed to customers through the FAC are proper.

In its Phase II Order in Cause No. 43426 ("Phase II Order") the Commission authorized Applicant and the other Joint Petitioners in that cause to recover costs and credit revenues related to the Ancillary Services Market ("ASM"). Mr. Daniel explained that Applicant has included various ASM charges and credits in this proceeding incurred for March through May 2022, consistent with the Phase II Order, as well as appropriate period adjustments.

Applicant's witness Mr. Scott A. Burnside testified that Applicant, in accordance with the Phase II Order, has calculated the monthly average ASM Cost Distribution Amounts it has paid for Regulation, Spinning and Supplemental Reserves. These amounts are as follows:

(in $ per MWh)	Mar-22	Apr-22	May-22
Regulation Cost Dist.	0.0669	0.1058	0.1125
Spinning Cost Dist.	0.0465	0.0751	0.0734
Supplemental Cost Dist.	0.0034	0.0069	0.0058

Applicant's treatment of ASM charges follows the treatment ordered by the Commission in its Phase II Order.

Based upon the evidence presented, we find Applicant's participation in the Energy and Ancillary Services Markets constituted reasonable efforts to generate or purchase power, or both, to serve its retail customers at the lowest fuel cost reasonably possible. Further, as we noted in our Orders in Cause Nos. 38707 FAC 81 and 38707 FAC 82, should Applicant's bidding strategy alter the native/non-native load assignment of its units, such strategy may be subject to further prudence review.

Additionally, based upon the evidence presented, the Commission finds that Applicant's treatment of the Energy and ASM charges and credits in its cost of fuel is consistent with the June 1 Order, the December 28, 2006 Order in Cause No. 38707 FAC 70, as well as the Commission's Phase I and Phase II Orders in Cause No. 43426, and should be approved.

We find that Applicant has laid a reasonable foundation for the mechanics of its supply offer adjustment to MISO in order to maintain a reliable level of coal inventory going into the winter months. Applicant will continue to provide support for the reasonableness of any supply offer adjustment in its next FAC filing.

7. Major Forced Outages. In the December 28, 2011 Order in Cause No. 38707 FAC 90, the Commission ordered Applicant to discuss in future FAC proceedings major forced outages of units of 100 MW or more lasting more than 100 hours. Mr. Daniel testified during this FAC period there were three outages that met these criteria. Mr. Daniel testified that no Root Cause Analysis was performed for any of these outages.

8. Operating Expenses. Ind. Code § 8-1-2-42(d)(2) requires the Commission to determine whether actual increases in fuel costs have been offset by actual decreases in other operating expenses. Accordingly, Applicant filed operating cost data for the 12 months ended May 31, 2022 (*see* Applicant's Ex. 6, Attachment 6-A, p.1). Applicant's authorized phased-in jurisdictional operating expenses (excluding fuel costs) are $1,321,526,000. For the 12-month period ended May 31, 2022, Applicant's actual jurisdictional operating expenses (excluding fuel costs) totaled $1,437,832,000. Accordingly, Applicant's actual operating expenses exceeded jurisdictional authorized levels during the period at issue in this Cause. Therefore, the Commission finds that Applicant's actual increases in fuel costs for the above referenced periods have not been offset by decreases in other jurisdictional operating expenses.

9. **Return Earned.** Ind. Code § 8-1-2-42(d)(3), subject to the provisions of Ind. Code § 8-1-2-42.3, generally prohibits a fuel cost adjustment charge that would result in regulated utilities earning a return in excess of its applicable authorized return. Should the fuel cost adjustment factor result in the utility earning a return more than its applicable authorized return, it must, in accordance with the provisions of Ind. Code § 8-1-2-42.3, determine if the sum of the differentials between actual earned returns and authorized returns for each of the 12-month periods considered during the relevant period is greater than zero. If so, a reduction to the fuel adjustment clause factor is deemed appropriate.

In accordance with the Commission's June 27, 2012 Order in Cause No. 42736 RTO 30, the proposal for Schedule 26-A treatment of costs or revenues associated with the Applicant's Company-owned Multi-Value Projects ("MVPs") should be addressed at the time any such projects have been completed and are included for recovery. Ms. Sieferman testified that the first of such projects were included for the first time in MISO billing effective June 2019. Applicant proposed that the costs and revenues associated with Company-owned MVPs be treated as non-jurisdictional and outside of the FAC earnings test, which is consistent with the treatment of its Company-owned Regional Expansion Criteria and Benefit projects beginning in Cause No. 38707 FAC 86. Applicant has provided more detail as it relates to the RTO rider in its filing in Cause No. 42736 RTO 56 ("RTO 56"). Based upon the evidence presented, the Commission approves Applicant's exclusion of revenues and expenses associated with Company-owned MVPs. In Cause No. 38707 FAC 122, Applicant's proposed treatment for these revenues and expenses were approved on an interim basis, subject to refund, pending the outcome of Applicant's RTO 56 filing. The Commission issued its RTO 56 Order on February 24, 2021.

In accordance with previous Commission Orders, Applicant's calculated jurisdictional electric operating income level was $505,690,000, while its authorized phased-in jurisdictional electric operating income level for purposes of Ind. Code § 8-1-2-42(d)(3), was $579,205,000 (*see* Applicant's Ex. 6, p. 10). Therefore, the Commission finds that Applicant did not earn a return more than its authorized level during the 12 months ended May 31, 2022.

10. **Estimation of Fuel Costs.** Applicant estimates that its prospective average fuel cost for the months of October through December 2022, will be $140,986,124 or $0.056518 per kWh (*see* Verified Application Attachment A, Schedule 1). Applicant previously made the following estimates of its fuel costs for the period March through May 2022, and experienced the following actual costs, resulting in percent deviation, as follows:

Month	Actual Cost in Mills/kWh	Estimated Cost in Mills/kWh	Percent Actual is Over (Under) Estimate
Mar 2022	43.511	30.561	42.37%
Apr 2022	47.522	33.696	41.03%
May 2022	54.588	31.251	74.68%
Weighted Average	48.489	31.777	52.59%

A comparison of Applicant's actual fuel costs with the respective estimated costs for these three periods results in a weighted average difference of 52.59%. (Verified Application, Attachment A, Schedule 10). Based on the evidence of record, we find Applicant's estimating techniques appear reasonably sound, and its estimates for October through December 2022 should be accepted.

11. <u>Fuel Cost Factor</u>. As discussed in Finding No. 3 above, Applicant's base cost of fuel is 26.955 mills per kWh. The evidence indicates that Applicant's fuel cost adjustment factor applicable to October through December 2022 billing cycles is computed as follows (Verified Application, Attachment A, Schedule 1):

	$ / kWh
Projected Average Fuel Cost	0.056518
FAC 133 Reconciliation Factor	0.008101
FAC 132 Reconciliation Factor	0.008284
Adjusted Fuel Cost Factor	0.072903
Less: Base Cost of Fuel Included in Rates	0.026955
Fuel Cost Adjustment Factor	0.045948

Ms. Sieferman testified that the under-collection for this reconciliation period is a result of the continued volatility in the fuel markets throughout this FAC. She further testified that the FAC 133 reconciliation factor shown above reflects $102,928,662 of under-billed fuel costs applicable to retail customers that occurred during the period March through May 2022, spread over a six-month recovery period instead of the normal three-month recovery period, resulting in $51,464,331 of the FAC 133 under-collection being included in the proposed fuel cost adjustment factor in this proceeding. In addition, the proposed fuel cost adjustment factor in this proceeding includes $52,627,460 for the remaining one-half of the reconciliation amount from FAC 132 ($105,254,919 under-collection) that was authorized to be spread over two FAC periods.

OUCC witness Mr. Guerrettaz testified that the fuel cost adjustment for the quarter ended May 2022 had been properly applied by Applicant. In addition, he stated the figures used in the Application for a change in the FAC were supported by Applicant's books and records, Sumatra, and source documentation of Applicant for the period reviewed. He recommended the variance for FAC 133 be spread over four quarters, rather than the two quarters proposed by Applicant. Mr. Eckert testified that the OUCC is concerned that spreading the variance over only two quarters will burden customers with extremely large bills.

Mr. Gorman testified that Applicant's purchased power reliance increased fuel expense by an estimated $128.8 million. Mr. Gorman recommended that this amount be disallowed from recovery in this FAC. In support of this recommendation, he explained that the adjustment assumes that 80% of Applicant's total energy is supplied with coal-fired generation and noted that this level is consistent with the level of energy expected to be supplied by coal and assumed in Applicant's Integrated Resource Plan. He also recommended the creation of a subdocket to investigate and address the supply offer adjustment, issues related to Applicant's coal supply agreements, Applicant's decisions on fuel choice at Edwardsport, and Applicant's hedging plan. In addition, he recommended a subdocket be created to further investigate the supply offer adjustment, issues related to its coal supply agreement, its decisions on fuel choice at Edwardsport, and its hedging plan.

In rebuttal, Ms. Sieferman testified that Applicant disagrees with the OUCC's proposal to spread the under-collection over 12 months because it would expose customers to the increase for a longer period of time. Spreading the variance over six months, as proposed by Applicant, reduces the customer impact by 5% over the normal three-month recovery. Spreading the variance over 12 months provides an additional 2% reduction but guarantees customers will be impacted by the current under-collection well into 2023. She testified it is prudent to spread the variance in a way that provides a meaningful reduction for customers while limiting the length customers would experience the increase. Since Applicant would have to fund the cash flow shortfall from the under-collected fuel expense through incremental short-term debt borrowings, spreading it beyond the normal three-month recovery period impacts Applicant through increased interest expense, increased leverage in the capital structure, and reduced liquidity.

Ms. Sieferman testified that Applicant disagrees with Mr. Gorman's recommended disallowance as his assertions of imprudence are unsupported, and a disallowance unwarranted. Further, she indicated that Mr. Gorman's 80% assumption related to load served with coal-fired generation is unreasonable. The 84% amount in Applicant's Integrated Resource Plan represents the percentage of generation that was sourced from burning or gasifying coal, not the percentage of customer load served by Applicant's coal generation. As shown in Applicant's FERC Form 1 filings for 2019 thru 2021, the percentage of customer load served by burning or gasifying coal at Applicant's generating stations was 54%, 55%, and 51%, respectively, which is far lower than Mr. Gorman's 80% assumption. Applicant's forecast in this current period reflects 58% of customer load being met by coal or coal-gasified generation, which is slightly higher, even considering the current coal supply and transportation constraints and Applicant's supply offer adjustment. Also, Mr. Gorman's calculation for purchased power was set to zero and repriced at the weighted average price for steam generation. Even moving all megawatts from purchased power to steam generation, the resulting steam percentage is still lower than 80%. Mr. Gorman's attempt to calculate a disallowance fails in part because the 80% assumption is inaccurate. Not only is this calculation different than how it has been characterized by Mr. Gorman, but it also reflects an unreasonable expectation that Applicant can or should meet 100% of customer demand with its own generation.

Applicant's proposal to spread recovery over six months will provide some meaningful rate relief for customers, rather than trying to collect the entire amount over one FAC period as they normally would. While it may not provide as much rate relief as spreading the recovery over 12 months, Applicant's proposal makes the most sense when balanced against the risk of pancaking that could occur over time if we continue spreading the recovery out over a longer period of time.[1] The Commission finds that spreading the under-collection over a six-month period, instead of the normal three-month recovery period as proposed by Applicant, is reasonable.

12. __Effect on Residential Customers__. The approved factor represents an increase of $0.011705 per kWh from the factor approved in FAC 132. The typical residential customer using 1,000 kWhs per month will experience an increase of $11.71 or 7.2% on the customer's total

[1] The factor in FAC 133 is already influenced by approximately $53M of remaining FAC 132 variance. Applicant's Ex. 6, p.17.

electric bill compared to the factor approved in FAC 132 (excluding sales tax). (Applicant's Ex. 6, p. 12).

13. Interim Rates. Because we are unable to determine whether Applicant's actual earned return will exceed the level authorized by the Commission during the period that this fuel cost adjustment factor is in effect, the Commission finds that the rates approved herein should be approved on an interim basis, subject to refund, in the event an excess return is earned.

14. Fuel Adjustment for Steam Service. On December 30, 1992, this Commission issued its Order in Cause No. 39483 approving the June 18, 1992 Settlement Agreement between Applicant and Premier Boxboard, formerly referred to as Temple-Inland, n/k/a International Paper which included a change in the method used to calculate International Paper's fuel cost adjustment as well as an update to the base cost of fuel. The fuel cost adjustment factor for International Paper of $4.2369937 per 1,000 pounds of steam was calculated on Attachment B, Schedule 1, of the Verified Application; this factor will be effective for the October through December 2022 billing cycles. Attachment B, Schedule 2, of the Verified Application is a reconciliation of the actual fuel cost incurred to estimated fuel cost billed to International Paper that resulted in $559,793 charge to International Paper for the months of March through May 2022.

The Commission finds that Applicant's proposed fuel cost adjustment factor for International Paper of $4.2369937 per 1,000 pounds of steam has been calculated in accordance with this Commission's Order in Cause No. 39483, and that such factor should be approved. We further find that Applicant's reconciliation amount of $559,793 charge to International Paper has been properly determined and should be approved.

15. Shared Return Revenue Credit Adjustment for International Paper. In accordance with the June 18, 1992 Settlement Agreement, International Paper will receive shared return revenue credit adjustments to the extent incurred. As indicated above in Finding No. 9, Applicant did not have excess earnings for the 12 months ended May 2022. Therefore, we find International Paper is not due a shared return revenue credit.

16. Confidential Information. On July 28, 2022, Applicant filed a motion requesting protection of confidential and proprietary information along with a supporting affidavit. On August 10, 2022, the Presiding Officers made a preliminary determination that trade secret information should be subject to confidential procedures, as supported by Applicant's affidavits, consisting of: (1) its coal procurement strategy plan, which includes fuel burn, contracting strategy, pricing, coal burn forecasts, supplier information, and activities related to Applicant's coal and transportation contracts; and (2) certain information concerning Applicant's adjusted supply offers to MISO between March and May 2022, including fuel inventory positions, power prices, and pricing projections. The Commission finds such information is trade secret as defined in Ind. Code § 24-2-3-2, is exempt from public access and disclosure pursuant to Ind. Code §§ 5-14-3-4 and 8-1-2-29, and should be held by the Commission as confidential and protected from public access and disclosure.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION that:

1. Duke Energy Indiana's fuel cost adjustment factor for electric service to be billed jurisdictional customers, as set forth in Finding No. 11, and the fuel cost adjustment for steam service as set forth in Finding No. 14 of this Order, are approved on an interim basis, subject to refund, in accordance with the Findings above.

2. Duke Energy Indiana's inclusion of Energy and Ancillary Services Markets charges and credits in its cost of fuel, as described in Finding No. 6 of this order, is approved.

3. Duke Energy Indiana is authorized to recover the $102,928,662 of under-collected fuel costs experienced in March through May 2022 over a six-month period, instead of the normal three-month recovery period, as set forth in Finding No. 11 above.

4. Prior to implementing the authorized rates, Applicant shall file the tariff and applicable rate schedules under this Cause for approval by the Commission's Energy Division. Such rates shall be effective on or after the date of approval for all bills rendered.

5. Duke Energy Indiana shall provide an update on the status of its coal inventories and transportation issues in its next FAC filing, as described in Finding No. 4 of this Order.

6. Duke Energy Indiana shall provide an update on the fuel hedging plan collaborative, as described in Finding No. 5 of this Order.

7. Duke Energy Indiana will provide support for the reasonableness of any supply offer adjustment in its next FAC filing, as discussed in Finding No. 6 of this Order.

8. The material submitted to the Commission under seal is declared to contain trade secret information as defined in Ind. Code § 24-2-3-2 and therefore is exempted from the public access requirements contained in Ind. Code ch. 5-14-3 and Ind. Code § 8-1-2-29.

9. This Order shall be effective on and after the date of its approval.

HUSTON, FREEMAN, KREVDA, VELETA, AND ZIEGNER CONCUR:

APPROVED: SEPT 28 2022

I hereby certify that the above is a true
and correct copy of the Order as approved.

Dana Kosco Digitally signed by Dana Kosco
Date: 2022.09.28 10:22:00
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Dana Kosco
Secretary of the Commission