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 134** **APPROVED: DEC 28 2022**

ORDER OF THE COMMISSION

Presiding Officers:
David E. Ziegner, Commissioner
Jennifer L. Schuster, Senior Administrative Law Judge

On October 31, 2022, Duke Energy Indiana, LLC ("Petitioner") 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 January, February, and March 2023 for electric and steam service. On November 7, 2022, Petitioner filed its Amended Verified Application.

On December 5, 2022, the Indiana Office of Utility Consumer Counselor ("OUCC") filed its audit report and testimony. Petitioner filed its rebuttal testimony on December 12, 2022.

A public evidentiary hearing was held in this Cause on December 19, 2022, at 9:30 a.m. in Room 222 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. Petitioner and the OUCC appeared at the hearing by counsel and offered their respective prefiled testimony and exhibits into the evidentiary record without objection.

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. Petitioner 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 Petitioner'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. Petitioner's Characteristics. Petitioner is a public utility corporation organized and existing under Indiana law with its principal office in Plainfield, Indiana. Petitioner is engaged in rendering electric utility service in Indiana and owns, operates, manages, and controls, among other things, plant and equipment within Indiana used for the production, transmission, delivery, and furnishing of such service to the public. Petitioner 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 Petitioner. The Commission's June 29 Order found that Petitioner's base cost of fuel should be 26.955 mills per kWh and that Petitioner'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.

Petitioner's cost of fuel to generate electricity and the cost of fuel included in the net cost of purchased electricity for the month of August 2022, based on the latest data known to Petitioner at the time of filing after excluding prior period costs, hedging, and miscellaneous fuel adjustments, if applicable, was $0.061757 per kWh as shown on Petitioner's Attachment A, Schedule 9. In accordance with previous Commission Orders, Petitioner calculated its phased-in authorized jurisdictional net operating income level for the 12-month period ending August 31, 2022, to be $581,078,000. No evidence was offered objecting to the calculation of the authorized jurisdictional net operating income level proposed by Petitioner, and we find it to be proper.

4. Fuel Purchases. Shawn D. Shultz testified regarding Petitioner's coal procurement practices and its coal inventories. Mr. Shultz testified that, as of August 31, 2022, coal inventories were approximately 1,685,739 tons (or 33 days of coal supply), which is a decrease from inventories reported in Cause No. 38707 FAC 133 ("FAC 133"). Mr. Shultz reported that the decrease can be attributed to the price adjustment discussed by J. Bradley Daniel and weather-driven demand throughout the FAC period. He testified that Petitioner 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, included the continuation of onsite third-party train operations to alleviate railroad labor constraints, maintaining truck deliveries where logistically feasible, and adjusting shipping schedules to maximize efficiencies. Mr. Shultz stated that in cases where actual burns unexpectedly drop below projections and inventory levels are above target, as inventory levels dictate, Petitioner explores options to store or defer contract coal or resell surplus coal into the market. In cases where actual burns unexpectedly increase above projections, Petitioner 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 and volatile and can change significantly day to day based on market fundamental drivers. During the three-month period from June through August 2022, the price Petitioner paid for delivered natural gas at its gas burning stations was between $5.45 per million BTU and $9.64 per million BTU. He testified natural gas prices for the period were above those experienced in the FAC 133 review period. Mr. Shultz testified that, in his opinion, Petitioner purchased natural gas at the lowest cost reasonably possible.

OUCC witness Michael D. Eckert testified that Petitioner is actively trying to manage its coal purchases and inventory. Although additional coal has been secured for 2022-2023, Petitioner is struggling to acquire and maintain adequate transportation of coal to its stations. He testified that while Petitioner 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. He also testified Petitioner's coal inventory issues caused Duke Energy Indiana to divert coal from Edwardsport to Cayuga. Mr. Eckert recommended Petitioner continue to update the Commission on its coal inventory and 2022 projected coal burn and coal purchases, as well as how Petitioner is addressing its coal transportation issues. OUCC witness Gregory T. Guerrettaz recommended Petitioner provide options considered to improve coal transportation if services were curtailed or interrupted.

In rebuttal, Mr. Shultz testified that 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, Petitioner, 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. Petitioner has actively requested improved performance from its rail transportation providers, including how it could incentivize better performance. Mr. Shultz testified Petitioner was proactively communicating with its rail transportation providers for improved rail performance prior to complaints being filed with the STB. Petitioner did not file its own complaint with STB, but instead participated through its membership in the National Coal Transportation Association ("NCTA"). Petitioner also 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 Petitioner. Mr. Shultz testified that, regardless of the STB process, Petitioner 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. He also testified that Petitioner did not modify the operations of Edwardsport to support coal deliveries to Cayuga during this FAC period as alleged by Mr. Eckert.

Mr. Daniel testified that Petitioner 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.

Based on the evidence presented, we find that Petitioner made every reasonable effort to acquire fuel for its own generation or to purchase power to provide electricity to its retail customers at the lowest fuel cost reasonably possible during June through August 2022. Regarding its coal inventory levels and transportation issues, Petitioner will provide an update on the status in its next FAC proceeding as recommended by the OUCC.

5. <u>Hedging Activities</u>. Petitioner's witness James J. McClay, III testified Petitioner takes advantage of the hedging tools available to protect against natural gas price fluctuations. Mr. McClay testified that Petitioner realized a gain of $14,345,491 from natural gas hedges purchased for June through August 2022. He testified that the market price for gas realized higher values than the hedged prices due to strong price increases triggered by the Russian invasion of Ukraine. He testified Petitioner experienced net realized power hedging gains for the period of $12,470,670 primarily due to geopolitical concern in Europe and continued disruptions in coal supply. Petitioner's witness Suzanne E. Sieferman testified that Petitioner realized a total net hedging gain of $26,802,391 during the period for all native gas and power hedging activities other than MISO virtual energy market participation (including prior period adjustments).

Mr. McClay 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, Petitioner has not utilized its flat hedging methodology. Rather, Petitioner 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 Petitioner with at least 150 MW of expected load unhedged on a forward-forecasted basis. Mr. McClay opined Petitioner's gas and power hedging practices are reasonable. He stated Petitioner never speculates on future prices and that its hedging practice is economic at the time the decision is made and reduces volatility because Petitioner is transacting in a less volatile forward market, as opposed to more volatile spot markets. Mr. McClay testified that, as instructed by the Commission in Cause No. 38707 FAC 133, Petitioner will be meeting with the OUCC and industrial customers prior to the end of November 2022 to discuss potential changes to its hedging program.

Mr. Eckert testified that Petitioner's hedging gains and losses for the period December 2013 through August 2022 were relatively consistent. Starting in February 2021, with the exception of March 2021, Petitioner experienced large hedging gains through November 2021. Petitioner subsequently experienced large hedging losses starting in December 2021 through February 2022. In the current FAC period, Petitioner experienced large gains in all three months. Mr. Eckert recommended Petitioner file testimony in its next FAC on the results of its informal hedging policy review. Mr. Guerrettaz testified that any new hedging program should lower/eliminate the need to forecast a cost impact in the proposed calculation of total fuel cost (F) divided by sales (S) (Schedule 1, Attachment A). He further recommended Petitioner document any significant change in Petitioner's hedging position or policy.

In rebuttal, Mr. McClay testified that Petitioner will continue to work with the OUCC, Commission staff, and its industrial customers to ensure Duke Energy Indiana's hedging program serves its purpose of limiting customer exposure to actual market prices and mitigating fuel and power price volatility in uncertain markets.

Petitioner presented evidence that its power hedging practices relevant to this proceeding were consistent with the Agreement previously approved in the FAC 68 S1 Order. Thus, we allow Petitioner to include $26,802,391 of net gains from native gas and power hedges in the calculation of fuel costs in this proceeding. Further, consistent with our Order in FAC 133, Petitioner should update the Commission in future FAC proceedings on the status of the collaborative process regarding possible changes to Petitioner's hedging plan.

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 Petitioner included Energy Markets charges and credits incurred as a cost of reliably meeting the power needs of Petitioner's load, including: (1) Energy Markets charges and credits associated with Petitioner's own generation and bilateral purchases that were used to serve retail load; (2) purchases from MISO at the full locational marginal pricing at Petitioner'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 continued constraints in the coal supply and transportation market, along with sustained strength in spot and future natural gas and power prices through the FAC 134 period, continued the need for Petitioner'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 supply offer adjustments remain necessary to provide reliable station fuel inventory targets for the winter season. In the current constrained environment, without a supply offer adjustment, Petitioner's coal inventory would drop to low and unreliable levels. Mr. Daniel testified Petitioner 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. Petitioner 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 Petitioner'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 June through August 2022.

Mr. Daniel testified the adjustment to economic offers at Wheatland CT continued through this FAC period, with 12-month rolling NOx tons emissions decreasing to 123 tons. Petitioner continues to use an adjustment to its economic offers to optimize its rolling 12-month permit allowance.

Mr. Eckert testified the OUCC understands Petitioner's need for the coal increment to maintain a reasonable level of coal inventory and meet reliability concerns in MISO. He recommended Petitioner file testimony, schedules, and workpapers to justify the need for, or use of, coal increment/decrement pricing in its next FAC proceeding. Mr. Guerrettaz testified that delivery constraints, which are changing weekly, were the main driver of the adder. Petitioner's weekly analysis showed that if an adder was not implemented, its inventory would quickly decrease to zero.

Petitioner's witness Mary Ann Amburgey testified as to the procedures followed by Petitioner to verify the accuracy of the charges and credits allocated by MISO and PJM to Petitioner. 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 Petitioner 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 Petitioner 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 Petitioner 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 Petitioner has included various ASM charges and credits in this proceeding incurred for June through August 2022, consistent with the Phase II Order, as well as appropriate period adjustments.

Petitioner's witness Scott A. Burnside testified that Petitioner, 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)	**June 2022**	**July 2022**	**August 2022**
Regulation Cost Distribution	0.0755	0.0631	0.0649
Spinning Cost Distribution	0.0542	0.0195	0.0270
Supplemental Cost Distribution	0.0138	0.0312	0.0118

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

Based upon the evidence presented, we find Petitioner'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 Petitioner's bidding strategy alter the native/non-native load assignment of its units, such strategy may be subject to further prudence review.

In addition, based upon the evidence presented, the Commission finds that Petitioner'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 Petitioner has laid a reasonable foundation for the mechanics of its supply offer adjustment to MISO to maintain a reliable level of coal inventory going into the winter months. Petitioner will continue to provide support for the reasonableness of any supply offer adjustment in its next FAC filing.

7. **<u>Major Forced Outages</u>.** In the December 28, 2011 Order in Cause No. 38707 FAC 90, the Commission ordered Petitioner 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 five outages that met these criteria. Mr. Daniel testified that no Root Cause Analyses was performed for any of these outages.

8. **<u>Operating Expenses</u>.** 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, Petitioner filed operating cost data for the 12 months ended August 31, 2022. Petitioner's authorized phased-in jurisdictional operating expenses (excluding fuel costs) are $1,321,966,000. For the 12-month period ended August 31, 2022, Petitioner's actual jurisdictional operating expenses (excluding fuel costs) totaled $1,473,926,000. Accordingly, Petitioner's actual operating expenses exceeded jurisdictional authorized levels during the period at issue in this Cause. Therefore, the Commission finds that Petitioner's actual increases in fuel costs for the above referenced periods have not been offset by decreases in other jurisdictional operating expenses.

9. **<u>Return Earned</u>.** 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 Petitioner-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. Petitioner proposed that the costs and revenues associated with Petitioner-owned MVPs be treated as non-jurisdictional and outside of the FAC earnings test, which is consistent with the treatment of its Petitioner-owned Regional Expansion Criteria and Benefit projects beginning in Cause No. 38707 FAC 86. Petitioner 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 Petitioner's exclusion of revenues and expenses associated with Petitioner-owned MVPs. In Cause No. 38707 FAC 122, Petitioner's proposed treatment for these revenues and expenses were approved on an interim basis, subject to refund, pending the outcome of Petitioner's RTO 56 filing. The Commission issued its RTO 56 Order on February 24, 2021.

In accordance with previous Commission Orders, Petitioner's calculated jurisdictional electric operating income level was $499,565,000, while its authorized phased-in jurisdictional electric operating income level for purposes of Ind. Code § 8-1-2-42(d)(3), was $581,078,000. Therefore, the Commission finds that Petitioner did not earn a return more than its authorized level during the 12 months ended August 31, 2022.

10. Estimation of Fuel Costs. Petitioner estimates that its prospective average fuel cost for the months of January through March 2023 will be $113,221,458 or $0.043438 per kWh (*see* Amended Verified Application Attachment A, Schedule 1). Petitioner previously made the following estimates of its fuel costs for the period June through August 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
June 2022	$49.535	$31.676	56.38%
July 2022	$56.127	$45.216	24.13%
August 2022	$59.565	$47.497	25.41%
Weighted Average	$55.218	$41.837	31.98%

A comparison of Petitioner's actual fuel costs with the respective estimated costs for these three periods results in a weighted average difference of 31.98%. (Amended Verified Application, Attachment A, Schedule 10). Based on the evidence of record, we find Petitioner's estimating techniques appear reasonably sound, and its estimates for January through March 2023 should be accepted.

11. Fuel Cost Factor. As discussed in Finding No. 3 above, Petitioner's base cost of fuel is 26.955 mills per kWh. The evidence indicates that Petitioner's fuel cost adjustment factor applicable to January through March 2023 billing cycles is computed as follows (Amended Verified Application, Attachment A, Schedule 1):

	$ / kWh
Projected Average Fuel Cost	0.043438
FAC 134 Reconciliation Factor	0.012407
FAC 133 Reconciliation Factor	0.007258
Adjusted Fuel Cost Factor	0.063103
Less: Base Cost of Fuel Included in Rates	0.026955
Fuel Cost Adjustment Factor	0.036148

Ms. Sieferman testified that the FAC 134 reconciliation factor shown above reflects $87,976,055 of under-billed fuel costs applicable to retail customers that occurred during the period June through August 2022. In addition, the proposed fuel cost adjustment factor in this proceeding includes $51,464,331 for the remaining one-half of the reconciliation amount from FAC 133 ($102,928,662 under-collection) that was authorized to be spread over two FAC periods.

Mr. Guerrettaz testified that the fuel cost adjustment for the quarter ended August 2022 had been properly applied by Petitioner. In addition, he stated the figures used in the Application for a change in the FAC were supported by Petitioner's books and records, Sumatra, and source documentation of Petitioner for the period reviewed.

12. **<u>Effect on Residential Customers</u>.** The approved factor represents a decrease of $0.00980 per kWh from the factor approved in FAC 133. The typical residential customer using 1,000 kWh per month will experience a decrease of $9.80 or 5.5% on the customer's total electric bill compared to the factor approved in FAC 133 (excluding sales tax).

13. **<u>Interim Rates</u>.** Because we are unable to determine whether Petitioner'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. **<u>Fuel Adjustment for Steam Service</u>.** On December 30, 1992, the Commission issued its Order in Cause No. 39483 approving the June 18, 1992 Settlement Agreement between Petitioner 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 $2.8818473 per 1,000 pounds of steam was calculated on Attachment B, Schedule 1, of the Amended Verified Application; this factor will be effective for the January through March 2023 billing cycles. Attachment B, Schedule 2, of the Amended Verified Application is a reconciliation of the actual fuel cost incurred to estimated fuel cost billed to International Paper that resulted in $386,606 charge to International Paper for the months of June through August 2022.

The Commission finds that Petitioner's proposed fuel cost adjustment factor for International Paper of $2.8818473 per 1,000 pounds of steam has been calculated in accordance with the Commission's Order in Cause No. 39483, and that such factor should be approved. We further find that Petitioner's reconciliation amount of $386,606 charge to International Paper has been properly determined and should be approved.

15. **<u>Shared Return Revenue Credit Adjustment for International Paper</u>.** In accordance with the June 18, 1992 Settlement Agreement, International Paper will receive shared return revenue credit adjustments to the extent incurred. As indicated herein, Petitioner did not have excess earnings for the 12 months ended August 2022. Therefore, we find International Paper is not due a shared return revenue credit.

16. **<u>Confidentiality</u>.** Petitioner filed a Motion for Protection of Confidential and Proprietary Information on October 31, 2022, supported by affidavits showing that certain documents to be submitted to the Commission were trade secret information within the scope of Ind. Code §§ 5-14-3-4 and 24-2-3-2. The Presiding Officers issued a docket entry on November 14, 2022, finding such information to be preliminarily confidential, after which such information was submitted under seal. No party objected to the confidential and proprietary nature of the information submitted under seal in this proceeding. We find the information is confidential pursuant to Ind. Code § 5-14-3-4 and Ind. Code § 24-2-3-2, is exempt from public access and disclosure by Indiana law, and shall continue to be held confidential and protected from public access and disclosure by the Commission.

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 to 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 all of 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 hereby approved.

3. Prior to implementing the authorized rates, Petitioner 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.

4. 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.

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

6. 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.

7. 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.

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

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

APPROVED: DEC 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: 2022.12.28 10:25:37
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Dana Kosco
Secretary of the Commission