ORIGINAL

Commissioner	Yes	No	Not Participating
Huston	√		
Bennett	√		
Freeman	√		
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 137** **APPROVED: SEP 27 2023**

ORDER OF THE COMMISSION

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

On July 31, 2023, Duke Energy Indiana, LLC ("Duke Energy Indiana" or "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 October, November, and December 2023 for electric and steam service.

On September 5, 2023, the Indiana Office of Utility Consumer Counselor ("OUCC") filed its audit report and testimony. Petitioner filed its rebuttal testimony on September 8, 2023.

A public evidentiary hearing was held in this Cause on September 18, 2023, at 9 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 of record, the Commission now finds:

1. Notice and 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 in 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 kilowatt-hour ("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 May 2023, 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 $0.035067 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 May 31, 2023 to be $590,441,000. 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. John A. Verderame, Vice President of Fuels and Systems Optimization, Duke Energy Corporation, testified regarding Petitioner's coal procurement practices and its coal inventories. Mr. Verderame testified that, as of May 31, 2023, coal inventories were approximately 3,232,105 tons (or 63 days of coal supply), which is an increase from inventories reported in Cause No. 38707 FAC 136 ("FAC 136"). Mr. Verderame reported that the increase can be attributed to the price adjustment discussed by J. Bradley Daniel, Director, Generation Dispatch and Operations in the Fuels and Systems Optimization Department, Duke Energy Carolinas, LLC, lack of weather-driven demand, and declining natural gas and power prices throughout the FAC period. Mr. Verderame testified that Petitioner continues to evaluate a host of options to effectively manage its coal inventory. He stated that additional inventory mitigation efforts, aside from the price adjustment, included halting truck deliveries to the stations. Mr. Verderame stated that, as inventory levels dictate, Petitioner explores options to store or defer contract coal or resell surplus coal into the market. According to Mr. Verderame, Petitioner continues to closely monitor its anticipated coal requirements and inventories and take every action available to effectively manage coal inventories in the least-cost impact manner for customers. He testified that, starting with FAC 136, the Fleet Analytics Stochastic Tool ("FAST") model outputs are being used as part of forecasting Petitioner's future fuel costs. The FAST model uses historic weather information to simulate numerous scenarios of future weather and commodity prices.

Mr. Verderame testified that spot natural gas prices are dynamic, volatile, and can significantly change day to day based on market fundamental drivers. During the three-month period from March through May 2023, the price Petitioner paid for delivered natural gas at its gas burning stations was between $1.65 per million BTU and $3.50 per million BTU. He testified natural gas prices for the period were below those experienced in the FAC 136 review period. Mr. Verderame opined that 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 2023, Mr. Eckert recommended that Petitioner continue to update the Commission on its coal inventory and 2023-2024 projected coal burn and coal purchases, as well as how Petitioner is addressing its coal transportation issues. OUCC witness Gregory T. Guerrettaz recommended Petitioner continue to provide daily coal inventory balances at each station and reasons for any adjustment to its Midcontinent Independent System Operator ("MISO") offers related to coal price.

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, as discussed in 38707 FAC 113.

Based on the evidence of record, 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 March through May 2023. 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. Hedging Activities. James J. McClay, III, Managing Director of Natural Gas Trading for Duke Energy Corporation, testified that Petitioner takes advantage of the hedging tools available to protect against natural gas price fluctuations. He stated that Petitioner realized a loss of $15,810,388 from natural gas hedges purchased for March through May 2023. He testified that market prices for gas realized much lower values than the hedged prices due to decreased natural gas prices caused by improved domestic production, lower LNG processing demand, and mild spring weather. He testified Petitioner experienced net realized power hedging losses for the period of $8,404,107 primarily due to low power prices due to mild spring weather, increased natural gas production, improved U.S. natural gas storage inventories, and improvement in coal delivery. Christa L. Graft, Manager of Rates and Regulatory Strategy for Petitioner, testified that Petitioner realized a total net hedging loss of $24,226,771 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 megawatts ("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 testified that changes were made to Petitioner's power and gas hedging plans, as approved in the Commission's March 29, 2023 Order in Cause No. 38707 FAC 135, to extend the rolling native power hedging horizon to cash month plus 12 months and the native gas hedging term limit to cash month plus three years, with target ranges for the new horizon period for natural gas adjusting over time to allow Petitioner to layer in hedges. He testified that the different proposed hedging extensions (12 months power hedging versus three years gas hedging) are driven by liquidity differential in the two markets. While natural gas has a robust futures market, power forward markets are not as active and have much lower trading volumes. Mr. McClay opined that it is necessary to keep a more realistic shorter-term limit for power hedges. He testified Petitioner's updated Duke Energy Indiana Risk Management Guidelines with the new power and gas limits were internally approved on June 15, 2023. Petitioner began to layer in additional power and gas hedges over time toward the new target ranges.

Mr. McClay opined that 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. Eckert testified that Petitioner's hedging gains and losses for the period December 2013 through January 2021 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 losses in all three months. Mr. Eckert recommended Petitioner continue to update the Commission on its coal hedging policy.

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 $24,226,771 of net losses from native gas and power hedges in the calculation of fuel costs in this proceeding. We also conclude that it is prudent for Duke Energy Indiana to periodically consult with the OUCC to review Petitioner's hedging program and recommend modifications, as needed, in response to changing market signals to ensure that it remains appropriate based on market conditions.

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 the Commission 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 Petitioner will continue the use of supply offer adjustments at Gibson Units 1-5 and Cayuga Units 1-2 as a normal course of business to economically and reliably manage commitment and dispatch of its coal generators while continuing to achieve a reliable level of coal inventory. The offer adjustment process allows Petitioner to continue to economically commit and dispatch its units versus being forced to utilize higher cost options to manage its coal inventory. Over the course of the FAC period, as energy prices declined and supply chain constraints alleviated, Petitioner met its objective of achieving reliable fuel inventory for the winter season and the offer adjustment declined to $0/MWh for several weeks before oversupply conditions had to be addressed. Mr. Daniel testified Petitioner uses 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 Petitioner continues to bound coal inventory levels between a minimum and maximum full load burn inventory at Gibson and Cayuga stations for modeling purposes, as it does for fuel inventory planning and procurement purposes. He explained that the supply offers at Gibson Units 1-5 and Cayuga Units 1-2 are calculated just as they are normally, then adjusted 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 opined that the offer 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 March through May 2023.

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 Petitioner started using decrement pricing in March 2023 to control inventory, which is concerning to the OUCC. He recommended Duke Energy Indiana explain in the next FAC when the supply offer adjustment will be finished.

In rebuttal, Mr. Daniel testified that Petitioner expects to continue utilization of the supply offer adjustment as a normal course of business to proactively respond to the issues impacting fuel inventory reliability, which is in its customers' best interests.

Mary Ann Amburgey, Accounting Manager for Duke Energy Business Services LLC, discussed the procedures followed by Petitioner to verify the accuracy of the charges and credits allocated to Petitioner by MISO and PJM. She 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 March through May 2023, consistent with the Phase II Order, as well as appropriate period adjustments.

Scott A. Burnside, Director, Unit Commitment and Post Analysis for Duke Energy Carolinas LLC, 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)	March 2023	April 2023	May 2023
Regulation Cost Dist.	0.0516	0.0630	0.0580
Spinning Cost Dist.	0.0275	0.0443	0.0405
Supplemental Cost Dist.	0.0033	0.0035	0.0079

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

Based on the evidence of record, 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 on the evidence of record, 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, and the Phase I and Phase II Orders in Cause No. 43426, and is approved.

We find that Petitioner has laid a reasonable foundation for the mechanics of its supply offer adjustment to MISO. Petitioner 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 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 no outages that met these criteria.

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. Petitioner filed operating cost data for the 12 months ended May 31, 2023. Petitioner's authorized phased-in jurisdictional operating expenses (excluding fuel costs) are $1,324,289,000. For the 12-month period ended May 31, 2023, Petitioner's actual jurisdictional operating expenses (excluding fuel costs) totaled $1,369,397,000. 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. 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 a regulated utility 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. Graft 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 on the evidence of record, 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 $552,023,000, while its authorized phased-in jurisdictional electric operating income level for purposes of Ind. Code § 8-1-2-42(d)(3), was $590,441,000. Therefore, the Commission finds that Petitioner did not earn a return more than its authorized level during the 12 months ended May 31, 2023.

10. <u>Estimation of Fuel Costs</u>. Petitioner estimates that its prospective average fuel cost for the months of October through December 2023, will be $83,870,333 or $0.034311 per kWh. Petitioner previously made the following estimates of its fuel costs for the period March through May 2023, and experienced the following actual costs (excluding prior period adjustments), resulting in percent deviation, as follows:

Month	Actual Cost in Mills/kWh	Estimated Cost in Mills/kWh	% Actual is Over (Under) Estimate
March 2023	$34.884	$46.521	(25.01%)
April 2023	$29.104	$39.887	(27.03%)
May 2023	$38.105	$37.020	2.93%
Weighted Average	$33.954	$41.273	(17.73%)

A comparison of Petitioner's actual fuel costs with the respective estimated costs for these three periods results in a weighted average difference of (17.08)%, excluding prior period adjustments. Based on the evidence of record, we find Petitioner's estimating techniques appear reasonably sound, and its estimates for October through December 2023 should be accepted.

11. Fuel Cost Factor. As discussed 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 October through December 2023 billing cycles is computed as follows:

	$ / kWh
Projected Average Fuel Cost	0.034311
FAC 137 Reconciliation Factor	(0.000231)
Adjusted Fuel Cost Factor	0.034080
Less: Base Cost of Fuel Included in Rates	0.026955
Fuel Cost Adjustment Factor	0.007125

Ms. Graft testified that the FAC 137 reconciliation factor shown above reflects $1,419,598 of over-billed fuel costs applicable to retail customers that occurred during the period April 2022 through May 2023. She testified the reconciliation covers a 13-month period, rather than the typical three-month period, in order to provide a final reconciliation of April 2022 through February 2023. As discussed in Petitioner's prior FAC proceedings, in early April 2022 a new customer billing and technology system was implemented. There was a 12-month transition period during which Duke Energy Indiana experienced some delayed billings and conversion-related mapping and reporting challenges, resulting in the use of estimates in calculating the reconciliation amounts for the months of April 2022 through February 2023. Now that the transition period has passed, Petitioner completed a final reconciliation of April 2022 through May 2023. Ms. Graft also explained that Petitioner has changed how it determines its retail native load fuel costs subject to reconciliation. Although the previous process was reasonable, Petitioner believes the updated process of utilizing actual calendar month fuel costs in the reconciliation rather than an estimate of billing cycle fuel costs is more straightforward. It provides more assurance that Petitioner is collecting its actual fuel costs and is consistent with Duke Energy Indiana's approach to reconciliations in its other riders.

Ms. Graft testified Petitioner began receiving excess distributed generation ("EDG") from customers pursuant to Ind. Code ch. 8-1-40 in late 2022. As directed in the Commission's July 6, 2022 order in Cause No. 45508 approving Petitioner's EDG tariff, amounts credited to customers for EDG are recognized in its FAC proceeding. The native load fuel costs reflected on Schedule 7 of Attachment A to Petitioner's Verified Application include the EDG payments made to customers during this FAC reconciliation period.

Mr. Guerrettaz testified that the fuel cost adjustment for the quarter ended May 2023 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.

Based on the evidence of record, the Commission approves the fuel cost factor as proposed by Duke Energy Indiana.

12. **Effect on Residential Customers.** The approved factor represents an increase of \$0.002064 per kWh from the factor approved in FAC 136. The typical residential customer using 1,000 kWh per month will experience an increase of \$2.07, or 1.6%, on the customer's total electric bill compared to the factor approved in FAC 136 (excluding sales tax).

13. **Interim Rates.** 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. **Fuel Adjustment for Steam Service.** On January 18, 2023, the Commission issued its Order in Cause No. 45740 approving the Fifth Amendment to the Third Supplemental Agreement to the Agreement for High Pressure Steam Service between Duke Energy Indiana and International Paper Company (formerly TIN, Inc. (Temple-Inland) and Inland Container Corporation) ("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 \$0.6118706 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 2023 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 \$432,940 credit to International Paper for the months of March through May 2023.

The Commission finds that Petitioner's proposed fuel cost adjustment factor for International Paper of \$0.6118706 per 1,000 pounds of steam has been calculated in accordance with this Commission's Order in Cause No. 45740, and approve the same. We further find that Petitioner's reconciliation amount of \$432,940 credit to International Paper has been properly determined and approve the same.

15. **Shared Return Revenue Credit Adjustment for International Paper.** In accordance with the Order in Cause No. 45740, International Paper will receive shared return revenue credit adjustments to the extent incurred. Petitioner did not have excess earnings for the 12 months ended May 2023. Therefore, we find International Paper is not due a shared return revenue credit.

16. **Confidential Information.** Petitioner filed a Motion for Protection of Confidential and Proprietary Information ("Motion") on July 31, 2023, 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 August 23, 2023, 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, 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 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 as noted 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 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.

6. 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.

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

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

APPROVED: SEP 27 2023

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: 2023.09.27 10:16:34 -04'00'

Dana Kosco
Secretary of the Commission