ORIGINAL

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

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

APPLICATION OF INDIANAPOLIS POWER & LIGHT COMPANY D/B/A AES INDIANA FOR APPROVAL OF A FUEL COST FACTOR FOR ELECTRIC SERVICE DURING THE BILLING MONTHS OF SEPTEMBER 2023 THROUGH NOVEMBER 2023, IN ACCORDANCE WITH THE PROVISIONS OF I.C. 8-1-2-42, AND CONTINUED USE OF RATEMAKING TREATMENT FOR COSTS OF WIND POWER PURCHASES PURSUANT TO CAUSE NOS. 43485 AND 43740, AND CONTINUED RECOVERY OF THE COSTS OF THE FUEL HEDGING PLAN PURSUANT TO I.C. 8-1-2-42.	)	**CAUSE NO. 38703 FAC 140** **APPROVED: AUG 30 2023**

ORDER OF THE COMMISSION

Presiding Officer:
Loraine L. Seyfried, Chief Administrative Law Judge

On June 16, 2023, Indianapolis Power & Light Company d/b/a AES Indiana ("Applicant" or "AES Indiana") filed its Verified Application, direct testimony, attachments, and workpapers with the Indiana Utility Regulatory Commission ("Commission") for approval of: (1) a fuel adjustment charge ("FAC") factor to be applicable during the billing cycles of September 2023 through November 2023 (the "Forecast Period"); (2) the continued use of ratemaking treatment for the cost of wind power purchases pursuant to Cause Nos. 43485 and 43740; and (3) continued recovery of the costs of its fuel hedging plan. On July 17, 2023, Applicant filed a revision to its prefiled testimony.

On July 21, 2023, the Indiana Office of Utility Consumer Counselor ("OUCC") filed its report and direct testimony.

An evidentiary hearing was held at 9:30 a.m. on August 9, 2023, in Room 224, PNC Center, 101 West Washington Street, Indianapolis, Indiana. Applicant and the OUCC appeared and participated by counsel. At the evidentiary hearing, the OUCC noted corrections to its testimony that Applicant had identified as necessary. The OUCC advised, and Applicant concurred, that the corrections did not change the meaning of the testimony or the calculations. The revised OUCC testimony was received into the record with no objection, as was the testimony of Applicant.

Based upon applicable law and the evidence of record, the Commission finds as follows:

1. **Notice and Jurisdiction.** Notice of the evidentiary hearing was given and published by the Commission as required by law. Applicant is a "public utility" as that term is defined in Ind. Code § 8-1-2-1(a). Under Ind. Code § 8-1-2-42, the Commission has jurisdiction over changes to Applicant's fuel cost charge and the ratemaking treatment of its wind power

purchase costs and costs associated with a natural gas hedging plan. Therefore, the Commission has jurisdiction over Applicant and the subject matter of this Cause.

2. <u>Applicant's Characteristics</u>. AES Indiana is an electric generating utility and a corporation organized and existing under the laws of Indiana with its principal office in Indianapolis, Indiana. Applicant is engaged in rendering electric public utility service in Indiana. Applicant owns and operates plant and equipment within Indiana used for the production, transmission, delivery, and furnishing of electric service to the public.

3. <u>Efforts to Acquire Fuel and Generate or Purchase Power to Provide Electricity at the Lowest Reasonable Cost</u>. Applicant must comply with the statutory requirements of Ind. Code § 8-1-2-42(d)(1) by making every reasonable effort to acquire fuel and generate or purchase power, or both, to provide electricity to its retail customers at the lowest fuel cost reasonably possible. As discussed below, we find Applicant has satisfied these requirements.

David Jackson, Director, Commercial Operations, AES US Services, LLC explained Applicant's participation in the Midcontinent Independent System Operator ("MISO") Open Access Transmission and Energy Markets Tariff, the projected fuel related MISO costs for the Forecast Period, and the true-up of fuel-related MISO costs and revenues during February 2023 through April 2023 (the "Historical Period"). Mr. Jackson also testified about the benefits to customers of Applicant's participation in MISO, where resources are centrally dispatched by MISO using simultaneous co-optimization.

Mr. Jackson supported Applicant's purchases of coal, fuel oil, and natural gas for use in its generating stations. He testified that Harding Street and Petersburg manage their fuel oil purchases based on inventory set-points and regional market index pricing negotiated in a competitively bid contract. He explained Applicant currently has contracts with two coal producers and receives coal from up to three different mines. Mr. Jackson stated that Applicant verifies the reasonableness of its coal cost by using a competitive bidding process to award its coal contracts. Mr. Jackson discussed Applicant's use of the spot market and added that for some spot purchases when a formal competitive bid process might not be feasible, an informal survey of local coal providers is performed to assure that the agreed-upon price is at or below Applicant's next best alternative. He said Applicant uses spot purchases of coal to: (1) provide the differential requirement between Applicant's long-term contracts and its projected burn for the year; (2) test the quality and reliability of a producer; and (3) take advantage of occasional low price market opportunities when Applicant's projected inventory levels allow.

Mr. Jackson also testified regarding Applicant's unit commitment process. He said generally, Applicant looks at the predicted economic performance of each generating unit over a period of one week when deciding whether to commit the unit. The startup cost necessary to re-start the unit is also considered. Additionally, he said Applicant considers reliability, price certainty from running generation, and opportunities from participating in both Day Ahead and Real Time energy markets. Mr. Jackson testified that during seasonal periods (summer and winter) with historical high market prices and potential high load, Applicant maintains a generation mix that includes coal, natural gas, and renewables. He explained Applicant raises the minimum operating level when required to maintain reliability or for other operational reasons. He testified that under normal conditions, Applicant offers the Petersburg units to be dispatched by MISO between their minimum and maximum economic operation level.

Mr. Jackson testified the decision to offer a unit considers a wide range of factors. He said some factors considered are economic, such as the predicted prices in the near future market and the avoidance of start-up costs required to bring the unit back on-line. Some are operational, such as the time and manpower required to bring units back on-line, plant limitations, and wear and tear of cycling units designed for long-term base load operations. Finally, he said some considerations revolve around system reliability. He explained system reliability issues are particularly important during the winter and summer peaks and a system is more reliable when supported by a diverse fuel mix. He testified that units taken down do not always come back fully operational, and sudden system disruptions can cause significant price spikes as units struggle to come back on-line to fill the energy demand.

Mr. Jackson testified that the focus in a prudence inquiry is not whether a given decision or action produced a favorable or unfavorable result, but rather whether: (1) the process leading to the decision or action was a logical one; (2) the utility company used good judgment and applied appropriate standards; and (3) the utility reasonably relied on information and planning techniques known at the time. He concluded Applicant acted prudently with respect to the commitment and operation of Petersburg during the Historical Period. He further explained why it is not reasonable to rely solely on pricing to decide whether and how to commit Applicant's generating units and he discussed other factors considered, including the potential for significant price risk.

Mr. Jackson summarized the commitment status of the Petersburg units during the Historical Period. He explained that Applicant evaluated the visible power market prices versus the cost of the Petersburg units, and decisions were made based on market pricing that Applicant witnessed at the time commitment decisions were made.

Mr. Jackson testified Petersburg Unit 2 was typically committed as economic to MISO during the Historical Period. He said the periods that Petersburg Unit 3 was offered as must run were due to expected economic value and variable weather experienced in the market. He explained Petersburg Unit 4 spent much of the Historical Period as must run for station and system reliability. Mr. Jackson provided further detail on the Petersburg unit commitment decisions during the Historical Period and explained AES Indiana ran a short-term model (which provides 30-day forward looks) to track the economic value of the Petersburg units. He sponsored a copy of the model runs in Applicant's Exhibit 2-C, Confidential Attachment DJ-3. He added that non-economic factors were also considered in unit commitment decisions, including reliability, price certainty, operational needs, and avoidance of startup costs.

Mr. Jackson stated Applicant also performed a look back evaluation of Petersburg for the Historical Period using the value created during the actual unit commitment as well as other economic benefits including real-time optimization, make whole payments, Auction Revenue Rights, Financial Transmission Rights, and Marginal Loss Credits. He explained that while the analysis should not be used to judge the prudence of the unit commitment decisions, Applicant acknowledges that a look-back analysis can inform its decision-making on a going forward basis and support Applicant's ongoing effort to improve its modeling and decision process.

Mr. Jackson testified that Applicant considers both the long-term and short-term when making unit commitment decisions. He said the longer-term forecasts in each FAC are generated in a planning model that looks at the economic dispatch of the units on the day the model is run. He said as the future period becomes the actual period, the following drives commitment decisions:

market pricing, protecting customers from price risk, operational issues, and reliability. In other words, he said, Applicant makes unit commitment decisions based on circumstances as they exist during the actual period and assesses energy market decisions through a nearer-term forward-looking assessment. He said Applicant is continuing to improve its understanding of market conditions and costs associated with must run and other unit commitment decisions.

Mr. Jackson also updated the Commission on the short-term model Applicant uses to support and track the Petersburg unit commitment decisions. He said the model utilizes a combination of two types of trades to calculate the operating cost and potential margin for the Petersburg units. He discussed how the model works, the inputs into the model, and how volatilities and correlations are incorporated into the model. He said the model output is captured on a spreadsheet showing a rolling 30-day period and the total profit and loss from each of the two types of trades. The total value of the two trades indicates if the unit is in or out of the money. He said Applicant began using the model at the end of May 2020 and continues to use it to support commitment decisions. He said Applicant will include model output from the Historical Period in the OUCC packet for review and will review the model and output with the OUCC during the audit.

Mr. Jackson also provided an update on Applicant's 2023 projected coal burn and coal purchases. Mr. Jackson stated due to mild winter weather and falling natural gas prices, coal burns have not been as high as expected for the start of 2023, and current inventory is above the target range. He said Applicant continues to actively manage its inventory levels and expects coal inventory to remain above target through 2023. He noted Applicant's long-term coal contracts often contain some variability in the quantity of coal that Applicant can take under that particular contract. He said this allows Applicant to increase deliveries when coal burns go up and decrease deliveries when coal burns go down. He explained this contract variability is essential in managing the month-to-month variations in coal burns due to weather, market prices, and unit availability.

Mr. Jackson testified coal market conditions have changed since the end of 2022. More specifically, he noted mild weather and competition with natural gas has coal inventories building. He said coal burn forecasts have decreased due to power prices pulling back with the price decline in natural gas and end of winter burns that were not as substantial as previously forecast. He said expectations are for inventories to pull down into summer and build into next winter and that AES Indiana will work with suppliers as necessary to manage deliveries.

Mr. Jackson testified Applicant did not use coal decrement pricing during the Historical Period and there is no decrement pricing in the Forecast Period. He added that AES Indiana has not been impacted by any coal supply interruptions.

Mr. Jackson also discussed the natural gas transactions for the Eagle Valley CCGT that were completed under the fuel hedging policy approved in Cause No. 38703 FAC 133. He stated Applicant initiated the Long-Term Hedging Program for Eagle Valley on March 28, 2022. He said once the plant was online and running as expected, Applicant moved expeditiously and in accordance with the hedging plan to bring hedged volumes in line with approved guidelines. Mr. Jackson sponsored Attachment DJ-5 to Applicant's Exhibit 2, which provides an evaluation of the hedges' economic settlement in the Historical Period, by comparing the hedge price to the daily index price for the natural gas delivery point associated with the hedges. He testified that in the month of February 2023, hedges on natural gas represented a cost of $11,381,612. Hedges on natural gas in the month of March 2023 represented a cost of $2,291,777, and in the month of April 2023, hedges on natural gas represented a cost of $1,474,410. He stated Confidential Attachment DJ-6 of Applicant's Exhibit 2-C shows completed hedging transactions and remaining balances to be completed for the Long-Term Hedging Program. Mr. Jackson noted Applicant will provide hedging transactions, modeling to support hedge volumes, market pricing at the time of the transactions, and hedge settlement calculations in the confidential audit package provided to the OUCC and review the information in this FAC's audit.

Mr. Jackson explained that the natural gas hedges were transacted during the period leading up to winter in which there was a great deal of concern about the supply and demand balance of the natural gas market. He said supportive factors included: natural gas production was slow to respond to higher prices, summer demand from electric generation was high, export demand in the liquified natural gas ("LNG") market was expected to remain strong, and the war between Russia and Ukraine continued to support higher natural gas and coal prices due to concern of global supply interruption and trade embargos on Russian commodities. He explained coal markets were tight, and natural gas was expected to see increased burns from fuel switching due to availability concerns of coal on a national level. He added that changes in the Environmental Protection Agency's Seasonal NOx program also supported fuel switching from coal to natural gas. Mr. Jackson stated the natural gas markets were pricing risk premium associated with these concerns and their potential impact to natural gas storage levels necessary to support winter demand.

Mr. Jackson testified that going into winter, fundamentals of the natural gas market changed. Mild weather in the latter parts of injection season allowed winter storage levels for natural gas to reach levels that would support normal winter demand. Natural gas production increased in a late response to the high prices seen during the summer. Additionally, he said the United States' export demand was materially reduced by the June 2022 outage at the Freeport LNG, which extended through January 2023 and reduced export demand for gas to supply LNG by 15-20% over that time frame. He said during the Historical Period, weather remained mild, reducing heating demand for natural gas, and United States natural gas inventories moved in line with the five-year average, removing some of the risk associated with winter demand. He said that other than the brief Winter Storm Elliott, winter temperatures realized much warmer than normal. He noted February 2023 ranked as the third warmest on record, continuing the trend of milder weather. Mr. Jackson testified this impacted natural gas demand from both the electric generation and heating needs and pushed United States natural gas inventories above the five-year average. He explained natural gas prices reflected these changes, the winter premium was eliminated, and prices fell in line closer to historical levels.

Natalie Herr Coklow, Manager in Regulatory Accounting at AES U.S. Services, LLC, testified there were no purchased power financial hedges settled or transactional fees incurred during the Historical Period. She noted that physical hedges do not receive mark-to-market accounting treatment and thus there are no recognized gains or losses on physical hedges.

Michael D. Eckert, Director of the OUCC's Electric Division, provided an update on the status of the Petersburg units and when they were last called on by MISO to produce power. He testified Applicant's current coal inventory is above Applicant's target levels and indicated Applicant is actively looking at options to address its coal inventory. He recommended Applicant provide an update on its coal inventory and its 2023 projected coal burn and coal purchases in future FAC proceedings.

Mr. Eckert noted that Mr. Jackson provided the results of Applicant's natural gas hedging program. He recommended Applicant continue to file the results of its natural gas hedging program in each subsequent FAC, provide analysis of the facts and circumstances existing when the transactions were entered, and provide any revisions to its hedging program in future FAC proceedings, if revised.

Applicant presented substantial evidence regarding its unit commitment decision-making process, which shows Applicant considers both short-term and long-term vantage points. The record also shows Applicant has worked to improve its short-term decision making and documentation of expected market prices at the time decisions are made. While economics do not capture all the reasons for unit commitment, we continue to find the modeling will help Applicant support its decision-making and should allow Applicant to improve its process on a going forward basis. We find that price risk, reliability, and operational needs are also reasonably factored into Applicant's decision process. Summer and winter periods create different challenges, including the potential for high price events, which require unit commitment decisions to consider more than purely economic factors. Accordingly, substantial evidence demonstrates, and we find, that Applicant's Petersburg unit commitment decisions during the Historical Period were reasonably based on forward market price values at the time the decisions were made and reasonably considered noneconomic factors.

The record shows Applicant has and continues to take reasonable steps to manage its coal inventory during changing coal market conditions. The record further shows Applicant's current coal inventory, while above target levels, will continue to be monitored and inventories managed to ensure reliable coal supply. As recommended by the OUCC, we direct Applicant to update the Commission on how it proposes to address its coal inventory and its 2023 projected coal burn and coal purchases in its future FAC proceedings.

Applicant also presented substantial evidence regarding the results of its natural gas hedging program. The record shows Applicant's hedging analysis is consistent with the process used to inform hedge decisions for the financial power hedges entered into during previous FAC proceedings.

The record shows the OUCC did not oppose Applicant's hedges and we find Applicant's purchased power hedges, including the purchase of natural gas discussed by Applicant's witness Jackson, to be reasonable. Therefore, the Commission finds the incurred gains or losses are reasonable and recoverable through the FAC. Applicant shall continue to provide in its next FAC the information recommended by the OUCC regarding Applicant's hedging program.

Based upon the evidence presented, the Commission finds Applicant has made every reasonable effort to acquire fuel and generate or purchase power to provide electricity at the lowest fuel cost reasonably possible.

4. <u>MISO Market Related Activity</u>. Mr. Jackson testified that Applicant's calculation of costs for the Forecast Period is consistent with the Commission's June 1, 2005, Order in Cause No. 42685 and its June 30, 2009, Order in Cause No. 43426 ("Phase II Order"). Mr. Jackson described the MISO costs and revenues Applicant is seeking to recover in this FAC proceeding. He testified that consistent with the Commission's Order in Cause No. 38703 FAC 97 ("FAC 97 Order"), Applicant has included Demand Response Resource Uplift charges from MISO in its cost of fuel in this proceeding. Further, he testified consistent with the Commission's Order in Cause No. 38703 FAC 85 ("FAC 85 Order"), Applicant has included the credits and charges for Contingency Reserve Deployment Failure Charge Uplift Amounts in its cost of fuel in this proceeding. He also discussed Applicant's experience with MISO's Ancillary Services Market ("ASM") and testified that Day Ahead and Real Time market clearing prices for Regulation, Spinning, and Supplemental Reserves appear to be at reasonable levels consistent with market conditions. Mr. Jackson testified that Applicant's request for recovery of Revenue Sufficiency Guarantee ("RSG") Payments is consistent with the Commission's June 3, 2009, Order in Cause No. 43664 ("RSG Order") in which the Commission approved an "RSG Benchmark" calculation. Mr. Jackson presented the RSG Daily Benchmarks in Attachment DJ-1 to Applicant's Exhibit 2.

Mr. Eckert testified that Applicant's proposed ratemaking treatment for the ASM charge types follows the treatment ordered in the Commission's Phase II Order.

Based upon the evidence, the Commission finds Applicant's treatment of the ASM charge types and other fuel-related MISO costs and revenues is consistent with the Commission's Phase II, FAC 85, and FAC 97 Orders, and is approved. The Commission further finds Applicant's recovery of RSG Payments is consistent with the RSG Order and is approved.

5. <u>Purchased Power Costs Above Benchmark.</u> In its April 23, 2008, Order in Cause No. 43414 ("Purchased Power Order"), the Commission approved a benchmark triggering mechanism to assess the reasonableness of purchased power costs. Mr. Jackson explained that each day, a benchmark is established based upon a generic Gas Turbine ("GT"), using a generic GT heat rate of 12,500 btu/kWh and the day ahead natural gas prices for the New York Mercantile Exchange Henry Hub, plus a \$0.60/MMBtu gas transport charge for a generic gas-fired GT (together, the "Benchmark"). He explained that Applicant continues to follow the guidelines and procedures established in the Purchased Power Order. He stated that purchases made in MISO's economic dispatch regime to meet jurisdictional retail load are a cost of fuel and recoverable in the utility's FAC up to the actual cost or the Benchmark, whichever is lower.

Mr. Jackson testified Applicant incurred a total of \$218,267 of purchased power costs over the applicable Benchmarks during the Historical Period. He said Applicant makes power purchases when economical or due to unit unavailability. Mr. Jackson testified that consistent with the Purchased Power Order, Applicant has an opportunity to request recovery and justify the reasonableness of purchased power costs above the applicable Benchmark.

Applicant provided, in Attachment DJ-2 to Applicant's Exhibit 2, a summary of the purchased power volumes, costs, total of hourly purchased power costs above the applicable Benchmarks during the Historical Period, and the reasons for the purchases at-risk after consideration of MISO's economic dispatch. Mr. Jackson testified that utilizing the methodology approved in the Purchased Power Order, all of the purchased power is recoverable during the applicable accounting period. Mr. Jackson testified the total purchased power costs during the Historical Period are reasonable.

Mr. Eckert explained the purchased power over the Benchmark treatment is controlled by the Purchased Power Order and Applicant followed the guidelines and procedures established in that Order. He stated the OUCC calculated the same amount of purchased power over the

Benchmark as Applicant. He recommended the Commission allow Applicant to recover $218,267 in purchased power over the Benchmark.

The record shows Applicant has applied the guidelines and procedures established in the Purchased Power Order to calculate the amount of purchased power over the Benchmark, and the OUCC agreed Applicant should be allowed to recover $218,267 in purchased power costs that exceeded the Benchmark. Accordingly, the Commission finds that Applicant's request for recovery of its purchased power over the Benchmark is reasonable, consistent with the Commission's Purchased Power Order, and should be approved. We further find the total purchased power costs for this period are reasonable and reflect the impacts of MISO's economic dispatch of Applicant's units.

6. Operating Expenses. Ind. Code § 8-1-2-42(d)(2) requires the Commission to find that the utility's actual increases in fuel cost through the latest month for which actual fuel costs are available since the last Commission Order approving basic rates and charges of the utility have not been offset by actual decreases in other operating expenses. Ms. Coklow testified that Applicant's Exhibit 1, Attachment NHC-2 calculates the (d)(2) test, showing total jurisdictional operating expenses excluding fuel costs have increased.

OUCC witness Gregory T. Guerrettaz, Certified Public Accountant, agreed Applicant did not have decreases in other operating costs that could be used to offset fuel cost increases.

Based on the evidence in the record, the Commission finds Applicant's actual increases in fuel cost have not been offset by actual decreases in other operating expenses and complies with the statutory requirements of Ind. Code § 8-1-2-42(d)(2).

7. Return Earned. Subject to Ind. Code § 8-1-2-42.3, Ind. Code § 8-1-2-42(d)(3) requires the Commission to find that the FAC applied for will not result in the electric utility earning a return over the return authorized by the Commission in the last proceeding in which the basic rates and charges of the utility were approved.

Ms. Coklow explained Applicant's Exhibit 1, Attachments NHC-3 and NHC-4, which calculate the (d)(3) test, show Applicant's actual return for the 12 months ending April 30, 2023. She stated that Applicant's actual return is less than its authorized return for the 12 months ending April 30, 2023. Accordingly, she stated no reduction in the fuel factor is required and the Commission should find that the "return" test of Ind. Code § 8-1-2-42.3 is satisfied.

Mr. Guerrettaz agreed Applicant had jurisdictional net operating income (for the 12 months ending April 30, 2023) less than that granted in its last general rate proceeding, as adjusted for applicable Environmental Compliance Cost Recovery and Transmission, Distribution, and Storage System Improvement Charge proceedings.

Upon our consideration of the record evidence, the Commission finds Applicant has properly determined the authorized operating income for the 12 months ending April 30, 2023. Thus, as reflected in Applicant's Exhibit 1, Attachment NHC-3, Applicant has an authorized return of $238,368,000 for purposes of this proceeding. Attachment NHC-2 to Applicant's Exhibit 1 calculates the (d)(3) test (lines 12-14), which shows that Applicant's actual return for the 12 months ending April 30, 2023, was $191,845,000. Therefore, the Commission finds that during the 12 month period ending April 30, 2023, Applicant did not earn a return in excess of its authorized return in compliance with the statutory requirements of Ind. Code § 8-1-2-42(d)(3).

8. **<u>Estimating Techniques</u>.** Ind. Code § 8-1-2-42(d)(4) requires the Commission to find a utility's estimate of its prospective average fuel costs for each month of the estimated three calendar months is reasonable after taking into consideration the actual fuel costs experienced and the estimated fuel costs for the three calendar months for which actual fuel costs are available. According to Applicant's Exhibit 1, Attachment NHC-1, Schedule 5, page 4 of 4, Applicant's weighted average deviation between forecast and actual fuel cost was an overestimate of 22.26% for the Historical Period.

Mr. Jackson explained the largest driver of the variance was the decrease in natural gas prices in the Historical Period. He said this reduced the cost of generation in Applicant's gas units and the price of purchased power. He said the February, March, and April 2023 Indianapolis temperature variance from normal were +7.7 degrees, -0.2 degrees, and +0.6 degrees, respectively. He said the key drivers of the natural gas price decrease began with a record warm winter in the United States, which decreased demand from heating and electric generation. He explained demand from natural gas exports of LNG was significantly impacted by the Freeport LNG outage, which remained out of service through most of the winter period. He said natural gas production increased, in a delayed response to higher prices seen last summer and the start of winter. He testified as a result of these events, natural gas storage levels in the United States went from deficit to surplus versus the five-year average, reducing concerns of domestic supply tightness.

Mr. Guerrettaz stated the OUCC performed a detailed review of Applicant's estimation model and noted the forecast had the following items affecting it: (1) daily changes in the price of natural gas; (2) daily changes of power prices for the MISO market; (3) recent hedges put into place; (4) Applicant's coal inventory; and (5) gas transportation contracts. He said based on the OUCC's analysis and what appeared during the audit to be only a small change in commodity pricing, the OUCC is recommending the projected Fuel ÷ Sales of 37.435 Mills per kWh be approved.

Based upon the evidence, we find Applicant's estimating techniques are reasonably accurate and its estimate of fuel costs for the Forecast Period is accepted.

9. **<u>Wind Power Purchase Agreements and Renewable Energy Credits</u>.** Mr. Jackson testified that purchases from the Hoosier Wind Park ("Hoosier") and Lakefield Wind Park ("Lakefield") are included in Applicant's actual and projected fuel costs. He discussed the amount of power received from Hoosier and Lakefield during the Historical Period. Pursuant to the Order in Cause No. 43740, Applicant is reflecting credits to jurisdictional fuel costs for off-system sales profits made possible because of the energy received from the power purchase agreement ("PPA") with Lakefield.

Mr. Jackson said Hoosier and Lakefield are both Dispatchable Intermittent Resources in the MISO market and can ramp quickly, largely avoiding negative locational marginal prices. He stated curtailed power is billable when certain criteria are met. He said the level of curtailments at Lakefield were higher than the level of curtailments experienced during the time period covered by the last FAC, and lower than the time period experienced one year ago. There were no billable curtailments at the Hoosier Wind Park for this FAC period.

OUCC witness Eckert noted that Mr. Jackson provided testimony to update the Commission on locational marginal prices at Lakefield and Hoosier. He stated Applicant offers Lakefield and Hoosier into the day-ahead market to mitigate the impact of negative locational marginal pricing in real-time.

In Cause Nos. 43485 and 43740, the Commission approved Applicant's request to recover the purchased power costs incurred under the Hoosier and Lakefield PPAs over their respective full 20-year terms. Based on the evidence presented, the Commission finds the requested costs are reasonable, and the Commission approves the ratemaking treatment of the wind PPA costs.

10. Reconciliation and Resulting Fuel Cost Factor for Electric Service. According to Applicant's Exhibit 1, Attachment NHC-1, Schedule 1, Applicant's total estimated cost of fuel for the Forecast Period is $112,797,142, and its total estimated sales are 3,013,161 kWh. Applicant's estimated cost of fuel, after taking into consideration the proposed reconciliation component, is $0.032938 per kWh. App. Ex. 1, Attachment NHC-1, Schedule 1, Line 37. Ms. Coklow discussed in detail how the FAC factor was calculated. As shown on Schedule 1 of Attachment NHC-1 to Applicant's Exhibit 1, when the adjusted fuel cost charge is reduced by the base cost of fuel, the result is the proposed fuel factor of $(0.003102) per kWh for the Forecast Period's billing cycles. Ms. Coklow testified that in relation to the factor currently in effect, the proposed factor will result in a decrease of $5.96 or 5.11% for a residential customer using 1,000 kWh per month.

OUCC witness Eckert recommended the Commission approve the proposed fuel cost factor.

The record shows the parties agree on the proposed fuel factor of $(0.003102) per kWh. With respect to the fuel factor approved herein, we further find AES Indiana shall follow the normal reconciliation process in subsequent FAC filings. Under Ind. Code § 8-1-2-42(a), the Commission finds the approved factor should become effective for all bills rendered for electric services during the first full billing month following issuance of this Order. As a result of the approved fuel cost factor, a residential customer using 1,000 kWh per month will experience a decrease of $5.96 or 5.11% on his or her electric bill as compared to the factor currently in effect.

11. Confidential Information. On June 16, 2023, Applicant filed a Motion for Protection and Nondisclosure of Confidential and Proprietary Information in this Cause, which was supported by an affidavit from Mr. Jackson showing that certain information to be submitted to the Commission was trade secret information as defined in Ind. Code § 24-2-3-2 and should be treated as confidential in accordance with Ind. Code §§ 5-14-3-4 and 8-1-2-29. In a June 23, 2023 Docket Entry, the Presiding Officers found the information should be held confidential on a preliminary basis, after which the information was submitted under seal. After review of the information and consideration of the affidavit, we find the information is trade secret information 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 shall be held as confidential and protected from public access and disclosure by the Commission.

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

1. Applicant's fuel cost factor as calculated and discussed at Finding Paragraph No. 10 above is approved.

2. Prior to implementing the approved rate, Applicant shall file the tariff and applicable rate schedules under this Cause for approval by the Commission's Energy Division. Such rate shall be effective on or after the Order date subject to Division review and agreement with the amounts reflected.

3. Applicant's ratemaking treatment for the cost of wind power purchases pursuant to the Commission's Orders in Cause Nos. 43485 and 43740 is approved.

4. Applicant is authorized to continue to request recovery of the gains or losses, including any associated transactional costs, arising from its hedging plan as a fuel cost through its FAC. Such gains or losses, including any associated transactional costs, shall be separately identified in the schedules supporting each such filing, and upon a finding of reasonableness shall be recoverable through Applicant's FAC.

5. In its next FAC filing, Applicant shall update the Commission on how it proposes to address its coal inventory and its 2023 projected coal burn and coal purchases.

6. The information filed in this Cause pursuant to Applicant's motion for protective order is deemed confidential pursuant to Ind. Code §§ 5-14-3-4 and 8-1-2-29, is exempt from public access and disclosure by Indiana law, and shall be held confidential and protected from public access and disclosure by the Commission.

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

<u>HUSTON, BENNETT, FREEMAN, VELETA, AND ZIEGNER CONCUR</u>:

APPROVED: AUG 30 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: 2023.08.30 10:15:09 -04'00'

Dana Kosco
Secretary of the Commission