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

ORIGINAL

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 2024 THROUGH NOVEMBER 2024, IN ACCORDANCE WITH THE PROVISIONS OF I.C. 8-1-2-42, 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 144** **APPROVED: AUG 28 2024**

ORDER OF THE COMMISSION

Presiding Officer:
Kehinde Akinro, Administrative Law Judge

On June 20, 2024 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 2024 through November 2024 (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 June 20, 2024, Applicant also filed a Motion for Protection and Nondisclosure of Confidential and Proprietary Information, which was granted on a preliminary basis by the Presiding Officers in a Docket Entry dated July 1, 2024.

On July 25, 2024, the Indiana Office of Utility Consumer Counselor ("OUCC") filed its report and direct testimony. On August 1, 2024, Applicant filed its Notice of Intent not to file rebuttal testimony.

An evidentiary hearing was held at 10:30 a.m. on August 12, 2024, in Room 224, PNC Center, 101 West Washington Street, Indianapolis, Indiana. Applicant and the OUCC appeared and participated by counsel. Applicant and the OUCC, by counsel, participated in the evidentiary hearing, and the parties' evidence was admitted into the record without objection.

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. Applicant's Characteristics. 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. Efforts to Acquire Fuel and Generate or Purchase Power to Provide Electricity at the Lowest Reasonable Cost. 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.

Alexander Dickerson, Manager, Wholesale Energy, AES Indiana, 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 2024 through April 2024 (the "Historical Period"). Mr. Dickerson 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. Dickerson 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. Dickerson stated that Applicant verifies the reasonableness of its coal cost by using a competitive bidding process to award its coal contracts. Mr. Dickerson 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 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. Dickerson 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. Dickerson 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. Dickerson 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. Dickerson 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. Dickerson summarized the commitment status of the Petersburg units during the Historical Period. He stated Petersburg Unit 3 and Unit 4 were offered as must run, outage, and economic. He said periods of must run were due to reliability, variable weather experienced in the market, and operational needs of the units, including management of the coal inventory at safe levels and contractual requirements for coal delivery. Periods of outage were due to both scheduled and forced outages. Mr. Dickerson testified Applicant evaluated weekly model runs for commitment decisions and that, overall, AES Indiana's operation of the Petersburg units was reasonably aligned with market prices.

Mr. Dickerson 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 Confidential Attachment AD-3 to Petitioner's Exhibit 2. 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. Dickerson 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. Dickerson testified 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. He testified that the more refined short term model Applicant began using in May 2020 improves the economic view of unit commitment on a rolling four-week period and said still important are non-economic factors such as predicted strong weather/high loads (hedge value), operational issues, and reliability, which will continue to be considered "must run" decisions.

Mr. Dickerson 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 includes model output from the Historical Period in the OUCC packet for review and reviews the model and output with the OUCC during the audit.

Mr. Dickerson also provided an update on Applicant's 2023-2024 projected coal burn, coal purchases, and coal inventory management activities. Mr. Dickerson stated due to mild winter weather and falling natural gas prices, coal burns have not been as high as expected for the first half of 2024. He testified Applicant's coal inventory is currently above the 25-50 day supply of coal inventory target range and inventory is expected to remain above target through 2024.

Mr. Dickerson testified Applicant continues to actively manage its inventory levels. 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, however contract variability is not always enough to manage the inventory.

Mr. Dickerson testified historically mild weather and comparably lower natural gas prices in 2023 through the winter of 2024 has caused coal inventories to remain near maximum safe levels. He noted coal burn forecasts have decreased due to power prices pulling back with the price decline in natural gas and mild weather that has been prevalent in the Eastern United States for the first half of 2024. He said while coal inventory levels are slightly down from the highs of last year, expectations for inventories to decrease further in the recent winter did not occur. Mr. Dickerson explained as an additional response to high inventory levels Applicant began must running a second unit during this FAC period to assist in managing the coal inventory level. He said as discussed in Applicant's last FAC, and mentioned by the OUCC in their testimony, Applicant has completed amendments to defer tonnage as well as amending contracts to reduce coal contract tonnage obligations for a cost. Furthermore, as the coal pile has continued to remain near maximum safe levels, Applicant completed another coal contract amendment to reduce the tonnage obligation to be delivered in 2024. He said this action was necessary to ensure that the coal pile starts declining in size for the safe and reliable operation of the plant and to create the pile as a storage alternative if low coal burns persist. He explained the contract amendment reflected in this FAC is the most economical choice for customers and that Applicant will continue to evaluate cost effective solutions to manage its coal inventory as necessary in the future.

Mr. Dickerson further discussed the coal contract amendment costs reflected in this FAC. He said AES Indiana amended a contract with a supplier to modify the tons for delivery in 2024. He stated the contract had a fixed quantity delivery obligation and did not include any volume flexibility. He explained the amendment reduced the monthly delivery obligation for the period April 2024 through December 2024, at a monthly cost. The amended coal contract costs, therefore, are allocated to the relevant period impacted by the changes (April 2024 through December 2024). He added that the contract amendment was included in the OUCC packet for review. Mr. Dickerson also explained how the coal contract amendment is consistent with the FAC (d)(1) test in that it helps manage fuel supply and optimizes the generation and purchase of power to provide electricity at the lowest cost reasonably possible.

Mr. Dickerson testified the immediate benefit for the period covered by the coal contract amendment is that Applicant replaced the fixed price coal with a fixed price natural gas purchase for the Eagle Valley plant that locked in a much lower generated price per MWh for customers. He said the cost for the contract amendment and the fixed price energy cost reduction for customers is calculated in Confidential Workpaper AD-2. He explained the net cost reduction that Applicant locked-in by amending the coal contract and at the same time making an explicit fixed price natural gas purchase to lock in the value is over $14 million as shown in the Workpaper. He stated this benefit flows to customers through the FAC and serves to reduce the overall fuel cost during the relevant period. Mr. Dickerson testified while the contract amendment helped economically address Applicant's coal needs in 2024, Applicant does need additional coal for delivery in 2025. In order to obtain offers for 2025 coal deliveries, Applicant issued an RFP. He said based on the RFP results and as shown in Confidential Workpaper AD-2, Applicant expects to deliver coal when it is needed in 2025 at a delivered price that is the equivalent of rolling tons from 2024 to 2025 at no cost.

Finally, Mr. Dickerson testified there is no decrement pricing in the Forecast Period and that Applicant has not been impacted by any coal supply interruptions.

Mr. Dickerson 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. Mr. Dickerson sponsored Attachment AD-5, 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 2024, hedges on natural gas represented a cost of $8,260,911. Hedges on natural gas in the month of March 2024 represented a cost of $1,901,774, and in the month of April 2024, hedges on natural gas represented a cost of $699,540. He stated Confidential Attachment AD-6 shows completed hedging transactions and remaining balances to be completed for the Long-Term Hedging Program. Mr. Dickerson 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. Dickerson explained that the natural gas hedges were transacted during the period of higher prices leading up to winter 2022, through the spring of 2023, and into the fall of 2023 as natural gas prices began to moderate. He explained the outcome of mild temperatures across the United States in winter 2022 and into spring 2023 changed natural gas fundamentals, suggesting that the market would have little trouble reaching its storage goals during injection season in 2023 to prepare for the winter season in 2023-2024. He noted summer weather was dominated by an El Niño weather event, which sets up temperatures to be above normal in the west and southwest and brings cooler temperatures into the Midwest and Eastern United States. He said the milder temperatures impacted natural gas demand from the electric generation sector, and natural gas production remained at high levels through the summer and into the fall, outpacing the demand from electric generation and liquefied natural gas ("LNG") exports. He said United States natural gas inventories are above the one-year and five-year average, removing some of the risk associated with having necessary supply for the winter demand. He stated natural gas prices reflected these changes, summer and fall premium was eliminated, and prices fell to levels lower than historical norms. Mr. Dickerson said global fundamental drivers of natural gas pricing have also diminished with Europe carrying high inventories of natural gas as they came out of winter. During the historical FAC period, weather was mild in the Eastern United States, reducing power prices, and impacting need for electric generation and residential and commercial heating demand. He said storage now stands well above the five-year average coming into the summer of 2024 and as a result has created a $2 cash market for natural gas.

Mr. Dickerson testified regarding the benefits to customers of the long-term hedging program. He explained Applicant developed the long-term hedging program to achieve three primary goals for its customers. He said the first goal was to increase the reliable delivery of natural gas to all gas-fired generation in Applicant's fleet. He explained this is achieved through purchasing third party delivered gas to Eagle Valley off of the REX pipeline. He stated that by utilizing third party firm capacity to deliver to Eagle Valley, more of Applicant's Texas Gas firm capacity can be utilized at Harding Street. He said this essentially enhances the firm transportation portfolio of Applicant to provide reliable fuel delivery. Mr. Dickerson said the second goal of purchasing REX volumes to Eagle Valley is due to the volatility of REX Zone 3 pricing that has been seen historically. He said by locking in a fixed price, that volatility is mitigated for those volumes. He testified the third and final goal of the program is to reduce the price volatility that is inherent within the natural gas market. He explained the purchases for the long-term hedging program are layered in over time to produce a dollar-cost-averaging effect that is meant to reduce that price volatility. He said these benefits to customers are focused on risk reduction – creating more predictable pricing and increasing reliability of physical gas delivery.

Mr. Dickerson concluded that AES Indiana made 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.

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 also 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 2024 projected coal burn and coal purchases in future FAC proceedings. Mr. Guerrettaz, CPA and President of Financial Solutions Group, Inc., testified the OUCC reviewed both amendments to Applicant's coal supply agreement and that the amendments were explained in detail during the FAC audit.

Mr. Eckert noted that Mr. Dickerson provided the results of Applicant's natural gas hedging program and additional information was provided during the FAC audit. 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 into, and provide copies of 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. While economics do not capture all the reasons for unit commitment, we continue to find the modeling will help Applicant support its decision-making. 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. As explained in Mr. Dickerson's testimony, Applicant amended a contract with a supplier to modify the tons for delivery in 2024. The record shows the coal contract amendment achieves two important objectives – (1) managing inventory to maintain safe levels for AES people at the Petersburg plant while meeting contractual obligations, and (2) optimizing the generation cost to provide electricity at the lowest cost reasonably possible. The record further shows Applicant examined options to achieve the lowest cost solution to managing the coal inventory at a level that is safe for operations. This was undertaken as part of Applicant's ongoing effort to acquire fuel and generate or purchase power or both so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible. As explained by Mr. Dickerson, during the Historical Period, power prices remained at levels that did not support previously forecasted coal burns. The evidence reflects that remaining below the maximum safe inventory level at Petersburg required modeled burns that were based on higher forecasted power prices compared to the actual realized power prices. As a result, inventories remained at a level approaching the safe pile limit and were forecast to exceed that limit for much of the year absent steps to reduce deliveries. Actions to affect the volume deliveries were therefore required. We find the steps taken by Applicant to manage the coal inventory, including the coal contract amendment, and other immediate and subsequent actions optimize the generation and purchase of power to create a lower fixed generation output cost for the benefit of customers.

The record reflects that the coal contract amendment costs were recorded in FERC account 501 as they are fuel costs associated with the cost of managing and maintaining reliable and safe fuel supply and inventory and are thus part of the price of fuel. We note this treatment is consistent with the coal contract amendment costs approved by the Commission for recovery in Applicant's FAC 143 proceeding. Accordingly, we approve the coal contract amendment costs that are reflected in this FAC. As recommended by the OUCC, we direct Applicant to update the Commission on its coal inventory and its 2024 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 Dickerson, 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. Dickerson 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. Dickerson 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. Dickerson 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. Dickerson presented the RSG Daily Benchmarks in Attachment AD-1.

Mr. Eckert testified that Applicant's proposed ratemaking treatment for the ASM charge types is consistent with the Commission's approved ratemaking treatment 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. Purchased Power Costs Above Benchmark. 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. Dickerson 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 Applicant continues to follow the guidelines and procedures established in the Purchased Power Order. He stated 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. Dickerson testified Applicant incurred a total of $702,249 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. Dickerson 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 AD-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. Dickerson testified that utilizing the methodology approved in the Purchased Power Order, all but $2,472 of the purchased power is recoverable during the applicable accounting period.

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 its 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 recovery should be allowed. Accordingly, the Commission finds that Applicant's request for recovery of its purchased power over the Benchmark (shown on Attachment AD 2 and discussed by Mr. Dickerson) 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.

Mr. Guerrettaz 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 January 31, 2024. She stated that Applicant's actual return is less than its authorized return for the 12 months ending April 30, 2024. 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, 2024) less than that granted in Cause No. 45029, as adjusted for various orders affecting the authorized operating income.

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, 2024. Thus, as reflected in Applicant's Exhibit 1, Attachment NHC-3, Applicant has an authorized return of $258,095,000 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, 2024, was $191,751,000. Therefore, the Commission finds that during the 12 month period ending April 30, 2024, 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. **Estimating Techniques.** 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 14.42% for the Historical Period.

Mr. Dickerson explained the majority of the variance is due to a mild February and March. He said the resulting natural gas generation and coal generation came in significantly lower than forecast, resulting in better prices for customers. He said the forecast fuel cost for the months of February, March, and April 2024 used a Henry Hub price of $3.85/MMBtu, $2.64/MMBtu, and $2.60/MMBtu, respectively, while realized Henry Hub values during the historical period were

$1.75/MMBtu in February 2024, $1.50/MMBtu in March 2024, and $1.59/MMBtu in April 2024. App. Ex. 2 at 21. He said the February, March, and April 2024 Indianapolis temperature variance from normal were +8.7 degrees, +5.8 degrees, and +2.5 degrees, respectively.

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) hedges put into place; (4) Applicant's coal inventory; and (5) gas contracts. Pub. Ex. 1 at 3. 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 35.620 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. Wind Power Purchase Agreements and Renewable Energy Credits. Mr. Dickerson 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. He testified that pursuant to the Order in Cause No. 45931, Applicant closed on the acquisition of Hoosier on February 29, 2024. He said this acquisition will allow customers the benefit of the energy from the park without having the power purchase agreement ("PPA") price in the contract reflected in the FAC factor in future periods. He added that 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. He stated that as explained in AES Indiana witness Coklow's testimony, per the settlement agreement approved in Cause No. 45911 the margin associated with the Lakefield Wind PPA will be included in the Off System Sales ("OSS") Margin Adjustment rider in the future.

Mr. Dickerson said Hoosier and Lakefield are 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 starting in March 2024, after the acquisition of Hoosier, Applicant no longer pays for any curtailments at Hoosier. He said there were 188 MWhs of billable curtailments at Hoosier for this FAC period. 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 higher than the time period experienced one year ago.

OUCC witness Eckert noted that Mr. Dickerson 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 $107,778,644 and its total estimated sales are 3,025,800 kWh. Applicant's estimated cost of fuel, after taking into consideration the proposed reconciliation component, is $0.031302 per kWh. Ms. Coklow explained the changes made to Attachment NHC-1 as a result of the basic rate case under Cause No. 45911. She explained the base cost of fuel on Attachment NHC-1 was updated to $0.039027 as per the Order in Cause No. 45911. Second, she said there is no longer a Lakefield PPA Adjustment included as the margin associated with the Lakefield PPA is proposed to be included in the Off System Sales rider in the future.

In addition, Ms. Coklow testified the Hardy Hills solar project was approved in Cause No. 45493 along with associated ratemaking treatment. She explained Hardy Hills reached partial in-service in December 2023 and full commercial operation date on May 1, 2024. She said AES Indiana received the first contract for differences ("CFD") expense invoice in February 2024 and its first cash disbursement receipt in March 2024. She testified these monthly charges and receipts are reflected on Attachment NHC-1 Schedule 4, lines 11 and 12, respectively and that these amounts are added to the fuel cost variance calculated on this same attachment. She stated the grand total of the fuel cost variance including CFD and cash disbursements then flows to Attachment NHC-1, Schedule 1, line 35. She explained monthly amounts for these transactions will be included in each FAC proceeding going forward.

Ms. Coklow discussed how the FAC factor was calculated. As shown on Schedule 1 of Attachment NHC-1 to Applicant's Exhibit 1, after taking into consideration the reconciliation of Applicant's estimated and actual fuel costs, and the inclusion of the FAC 133 S1 item, Applicant's estimated average cost of fuel for the Forecast Period is $0.031302 per kWh. As shown on Schedule 1 of Attachment NHC-1 to Applicant's Exhibit 1, when the adjusted fuel cost charges is reduced by the base cost of fuel approved in Cause No. 45911, the result is the proposed fuel factor of ($0.007725) 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 $4.29 or 3.22% for a residential customer using 1,000 kWh per month.

OUCC witness Eckert recommended the Commission approve the proposed fuel cost factor as calculated by OUCC witness Guerrettaz, which agrees with Applicant's calculation.

The record shows the parties agree on the proposed fuel factor of $(0.007725) 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.

11. Confidential Information. On June 20, 2024, Applicant filed a Motion for Protection and Nondisclosure of Confidential and Proprietary Information in this Cause, which was supported by an affidavit from Mr. Dickerson 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. The July 1, 2024 Docket Entry 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, the Commission finds 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 proposed fuel factor set forth in 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 its coal inventory and its 2024 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.

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

APPROVED: AUG 28 2024

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: 2024.08.28 10:12:28
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Dana Kosco
Secretary to the Commission