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 JUNE 2024 THROUGH AUGUST 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 143** **APPROVED: MAY 29 2024**

ORDER OF THE COMMISSION

Presiding Officer:
James F. Huston, Chairman
Kehinde Akinro, Administrative Law Judge

On March 15, 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 June 2024 through August 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 March 15, 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 on March 26, 2024.

On April 19, 2024, the Indiana Office of Utility Consumer Counselor ("OUCC") filed its report and direct testimony. On April 29, 2024, Applicant filed its rebuttal testimony and attachment. On April 29, 2024, Applicant also filed an Unopposed Motion for Continuance of Hearing, which motion was granted by Docket Entry the same day.

An evidentiary hearing was held at 1:30 p.m. on May 15, 2024, in Room 222, 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. The OUCC cross-examined Applicant's witnesses, Natalie Coklow and G. Aaron Cooper.

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

1. **<u>Notice and Jurisdiction</u>.** 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.

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 November 2023 through January 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 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. 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. He explained, in general, Petersburg Units 3 and 4 were offered as must run and outage during the historical FAC period. He said periods of must run were due to expected economic value and 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. He said periods of outage were due to both scheduled and forced outages. Mr. Dickerson provided further detail on the Petersburg units 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. App. Ex. 3 at 27-28. 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 non-economic factors are still important 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 and coal purchases. Mr. Dickerson stated due to mild winter weather and falling natural gas prices, coal burns have not been as high as expected for 2023 and the start of 2024. He noted that temperatures in December finished as the second warmest on record, and even with the extreme cold event in January it finished with slightly above normal temperatures overall. He said February ended as the third warmest on record, creating a winter that was the warmest on record. He said Applicant will continue to closely monitor projected coal burns and manage inventories to ensure reliable coal supply and safe plant operations. He said Applicant continues to actively manage its inventory levels and expects coal inventory to remain above target through 2024. 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 competition with natural gas in 2023 has coal inventories near maximum capacity. He said 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 much of 2023 and the start of 2024. He stated while inventory levels are down from the highs of last year, expectations for inventories to decrease further did not occur. He said, as an additional response to high inventory levels Applicant began must running a second unit to assist in managing the coal inventory level. He said Applicant has completed discussions with its suppliers to move tonnage from 2023 into 2024, when Applicant was expecting to be able to burn the coal. He explained that as discussed in the last FAC, and mentioned by the OUCC in their testimony, Applicant has completed amendments to defer tonnage as well as cancelling some of the coal shipments for a cost. He said Applicant will continue to evaluate cost effective solutions to manage its coal inventory as necessary in the future and the contract amendments will be included in the OUCC packet for review. Finally, Mr. Dickerson testified there is no decrement pricing in the Forecast Period and that AES Indiana 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 ("FAC 133"). He stated Applicant initiated the Long-Term Hedging Program for Eagle Valley on March 28, 2022. 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 November 2023, hedges on natural gas represented a cost of $1,308,140. Hedges on natural gas in the month of December 2023 represented a cost of $7,483,999, and in the month of January 2024, hedges on natural gas represented a cost of $1,206,174. 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 has 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 in line closer to historical levels. Mr. Dickerson said global fundamental drivers of natural gas pricing have also diminished with Europe carrying high inventories of natural gas as they went through summer and prepare for the winter. During the historical FAC period, weather was relatively mild in the Eastern United States, reducing power prices, and impacting demand from electric generation. He said storage now stands well above the five-year average coming into the end of winter 2023-24 and as a result has created sub-$2 natural gas prices in the cash market.

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. 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, 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 stated in Mr. Cooper's rebuttal and explained during cross-examination, coal deliveries were adjusted and a coal contract was amended to ensure safety because the coal pile had reached its maximum safe level while also maintaining adequate supply App. Ex. 4 at 8; Tr. at 41-42, 43. The word "reasonable" in the statutory (d)(1) test recognizes that safety considerations are necessarily considered in the utility's operations. Furthermore, the coal contract buyout was the reasonable low cost solution in this circumstance. Mr. Cooper testified that on the basis of fuel cost alone, AES Indiana reduced costs for the benefit of customers by approximately $1.2 million by buying out the contract obligation vs. burning the coal at the decrement offer price witness Jackson calculated in Cause No. 38703 FAC 142 ("FAC 142"). 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 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. MISO Market Related Activity. 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 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. Dickerson testified Applicant incurred a total of $468,562 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. App. Ex. 3 at 10; Attachment AD-2. Mr. Dickerson testified that utilizing the methodology approved in the Purchased Power Order, all but $22,014 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.

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 January 31, 2024. She stated that Applicant's actual return is less than its authorized return for the 12 months ending January 31, 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 January 31, 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 January 31, 2024. Thus, as reflected in Applicant's Exhibit 1, Attachment NHC-3, Applicant has an authorized return of $250,995,000 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 January 31, 2024, was $195,008,000. Therefore, the Commission finds that during the 12 month period ending January 31, 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 underestimate of 6.18% for the Historical Period.

Mr. Dickerson explained the majority of the variance is due to an extreme cold weather event in January that drove natural gas prices to much higher levels than forecast; those elevated prices lingered for a period after the event was complete. He said the forecast fuel cost for the months of November 2023, December 2023, and January 2024 used a Henry Hub price of \$2.98/MMBtu, \$3.70/MMBtu, and \$3.93/MMBtu, respectively, while realized Henry Hub values during the historical period were \$2.74/MMBtu in November 2023, \$2.53/MMBtu in December 2023, and \$3.20/MMBtu in January 2024. App. Ex. 3 at 21. He said the November 2023, December 2023, and January 2024 Indianapolis temperature variance from normal were +1.9 degrees, +7.5 degrees, and +0.5 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. 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 32.145 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 Hoosier without having to pay the power purchase agreement ("PPA") price in the contract for future FAC periods. He said, as noted in Cause No. 45931, this acquisition is expected to bring substantial savings to AES Indiana customers. 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, the settlement agreement in Applicant's rate case contemplates the margin associated with the Lakefield Wind PPA will be included in the Off System Sales 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 will no longer have to pay for any curtailments at

Hoosier. He said there were 2,324 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 $122,505,027,[1] and its total estimated sales are 3,810,995 kWh.[2] Applicant's estimated cost of fuel, after taking into consideration the proposed reconciliation component, is $0.035595 per kWh. App. Ex. 1, Attachment NHC-1, Schedule 1, Line 36. Ms. Coklow explained the changes made to Attachment NHC-1 as a result of the basic rate case under Cause No. 45911. She explained that as an order was expected prior to the implementation of FAC 143 rates in June 2024, the base cost of fuel on Attachment NHC-1 was updated to $0.039027. Second, she said there is no longer a Lakefield PPA Adjustment included on Line 29 as the margin associated with the Lakefield PPA is proposed to be included in the Off System Sales rider in the future. She said these changes are consistent with the settlement agreement filed in Applicant's rate case.

Ms. Coklow discussed 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 in Cause No. 45911, the result is the proposed fuel factor of ($0.003432) per kWh for the Forecast Period's billing cycles.[3] Ms. Coklow testified that in relation to the factor currently in effect, the proposed factor will result in a decrease of $0.55 or 0.41% 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. Mr. Guerrettaz testified the OUCC is recommending a lower factor than AES Indiana proposed due to coal contract buyout costs included in AES Indiana's request. Mr. Guerrettaz reviewed the coal contract amendments which reduced AES Indiana's contractual obligation to purchase coal. Mr. Guerrettaz discussed the cost incurred by AES Indiana under both amendments. Mr. Guerrettaz stated that AES Indiana is negotiating other coal contract amendments to cancel or defer coal tonnage but the amendment had not been finalized at the time of the OUCC audit. Mr. Guerrettaz recommended AES Indiana provide

---

[1] See column D, line 31.
[2] See column D, line 15.
[3] See line 38.

testimony on additional coal buyouts that developed in late March 2024 that were not included in the recovery period for this FAC.

Mr. Guerrettaz testified that the contract buyout amounts AES Indiana agreed to pay are not fuel costs AES Indiana incurred to generate electricity. In his view, they are costs AES Indiana incurred to revise contractual commitments AES Indiana's management entered into, not costs to purchase fuel or to generate electricity. Mr. Guerrettaz concluded therefore, that these costs do not meet the requirements of Ind. Code § 8-1-2-42. Mr. Guerrettaz said the OUCC recommends the Commission require AES Indiana to remove the contract amendment cost from the FAC because it is not a fuel cost incurred to generate electricity. He contended these are costs AES Indiana agreed to pay to cancel coal contracts.

On rebuttal, Ms. Coklow testified that Mr. Guerrettaz' argument is inconsistent with the Commission's prior orders explaining the scope of fuel costs that are recoverable through the FAC. She stated that as discussed by Mr. Cooper, the costs challenged by Mr. Guerrettaz are fuel costs associated with the cost of managing and maintaining reliable fuel supply and inventory. She said the recoverability of the challenged costs in the FAC is supported by prior Commission Orders. She explained that the accounting treatment for these costs speaks to why these costs should be recovered in the FAC.

Ms. Coklow said AES Indiana follows the Commission's accounting rules, which incorporate the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts ("USOA"). She testified that the coal contract amendment costs challenged by Mr. Guerrettaz are recorded to FERC account 501 and added that as far back as 1976, the Commission explained that costs allowed by account 151 (which includes those recorded to account 501) constitute fuel costs that are proper for recovery through FAC proceedings.

Ms. Coklow testified that the guidance from the Code of Federal Regulations states that account 151, Fuel Stock, includes the following:

1. The invoice price of fuel less any cash or other discounts.

2. Freight switching, demurrage and other transportation charges.

3. Excise taxes, purchasing agents' commissions, insurance and other expenses directly assignable to cost of fuel.

4. Operating, maintenance and depreciation expenses and ad valorem taxes on utility-owned transportation equipment used to transport fuel from the point of acquisition to the unloading point.

5. Lease or rental costs of transportation equipment used to transport fuel from the point of acquisition to the unloading point.

Ms. Coklow testified that the coal contract amendment costs at issue here are part of the price of fuel and fall under item 1 in the accounting guidance. She added that as shown in AES Indiana witness Cooper's rebuttal, these costs are fuel costs attributable to managing fuel inventory. She said this cost also falls under item 3 ("other expenses directly assignable to cost of fuel"). Ms. Coklow stated Applicant considers the contract amendment costs part of the coal contract and thus are directly assignable to the cost of fuel. She concluded the coal contract amendment costs are therefore "allowed by" and "listed in" account 151 and are recoverable through the FAC.

Ms. Coklow testified that the FERC chart of accounts designates account 501, Fuel, as costs initially charged to account 151 and cleared based on fuel usage. She explained that as fuel is used, fuel costs are expensed to account 501. She said these expensed fuel costs are a component of fuel costs included in the FAC filings' reconciliation months. She said FAC cost recovery is not limited to costs booked to account 151. She explained that account 151 is an inventory account on the balance sheet and said all fuel costs are not held in a balance sheet account. She added for example, that fuel costs in account 547 (fuel, natural gas) and account 555 (purchased power) are included in the FAC but do not have corresponding inventory balance sheet accounts and are expensed as incurred. Ms. Coklow said account 501 recognizes the expense during the period and explained that in this instance, costs tied to November and December 2023 coal deliveries were included in account 501 in this FAC 143 because those months are part of the reconciliation period in this filing.

Ms. Coklow testified that Applicant received FAC cost recovery treatment related to coal management costs in previous FAC filings, including FAC 111 and FAC 115.

On rebuttal, Mr. Cooper discussed why the challenged coal contract buyout costs are fuel costs reasonably incurred to generate electricity safely and why the actions taken by AES Indiana were prudent in managing fuel inventory necessarily maintained to generate electricity. The record shows that AES Indiana examined different options to find the lowest cost solution to managing the coal inventory at a level that is safe for operations. Mr. Cooper testified that buying out of a portion of the contractual obligation was the lowest cost, best alternative. He testified that customers benefited from lower cost MWh from AES Indiana's natural gas resources or lower priced purchased power as a result of Applicant's action.

Mr. Cooper discussed the statutory language quoted by Mr. Guerrettaz, as well as the statutory requirement commonly referred to as the "(d)(1) test" found in Ind. Code § 8-1-2-42 subpart (d), section (1). Mr. Cooper said this statutory language directs the utility to use "every reasonable effort" to produce "the lowest fuel cost reasonably possible." He testified that with respect to the acquisition of fuel, "every reasonable effort" necessarily includes actions to acquire and manage fuel supply and to do so in a way that optimizes the generation and purchase of power to provide electricity at the lowest cost reasonably possible. Mr. Cooper said Mr. Guerrettaz' contention that the cost of fuel to generate electricity does not include such costs should be rejected.

Mr. Cooper disagreed with Mr. Guerrettaz' contention that the coal contract amendment costs are not "costs to purchase fuel or to generate electricity." Mr. Cooper testified that fuel costs include the cost incurred to acquire, maintain, and prudently manage fuel stock, *i.e.* fuel inventory. He said these types of transactions to optimize value for customers and manage fuel inventory have long been recognized as fuel costs incurred to generate electricity, which necessarily includes the cost to acquire fuel. He testified that in each FAC filing, AES Indiana presents testimony on its fuel purchases, including its coal and natural gas contracts, its use of spot purchases of coal and procedures for negotiating long-term coal contracts, the importance of having a reliable supply of fuel as well as the efforts to manage projected coal burn, coal purchases and coal inventory. He said this testimony has long been accepted as part of the effort required to purchase fuel and generate electricity.

Mr. Cooper testified that the coal contract buyout challenged by the OUCC was entered into to manage coal inventory at the plant. He said AES Indiana examined different options to find the lowest cost solution to managing the coal inventory at a level that is safe for operations. He said 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."

Mr. Cooper testified that AES Indiana followed its Fuel Policy, approved in the Order for FAC 133, in making the purchase of the subject coal. He stated that as explained by AES Indiana witness David Jackson in FAC 142, one of the ways Applicant is managing the coal pile is to amend contracts to defer tonnage and cancel coal shipments for a cost. Mr. Cooper presented the Fuel Policy with his rebuttal testimony (Confidential Attachment GAC-1R) and explained that AES Indiana followed the policy.

Mr. Cooper testified that forecasted and actual burns fluctuate daily based on market economics and that leads to necessary changes to the original delivery plan. He stated that when AES Indiana entered into the subject coal purchase contract in April 2022, the forecasted coal burn for calendar 2023 was 3.8 million tons. He said the realized coal burn for 2023 was 2.2 million tons, a reduction of almost 1.6 million tons driven by falling power prices. He added that as a result, in October 2023, the coal pile reached its maximum safe level, adding that this means that no more coal could be added to the pile if coal deliveries exceeded coal burn. Mr. Cooper stated that to reasonably address this issue, coal deliveries were adjusted as much as possible under all contracts to ensure safe and reliable operations while also maintaining adequate supply, but additional action was necessary to fully address the coal supply because the coal pile had reached its maximum safe level.

Mr. Cooper added that the FAC statute directs Applicant to make "every reasonable effort to acquire fuel and generate or purchase power so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible." He said the word "reasonable" in this directive recognizes that safety considerations are necessarily considered in utility operations. Mr. Cooper explained why the coal contract buyout was the reasonable low cost solution in this circumstance.

Mr. Cooper testified that Mr. Guerrettaz' proposed exclusion of the challenged fuel costs is not consistent with Mr. Guerrettaz' testimony in FAC 142. Mr. Cooper explained that Mr. Guerrettaz' testimony in FAC 142 addressed these costs and did not challenge the prudence of these costs or question the fact that they are fuel costs. Mr. Cooper testified that the Commission's FAC 142 Order found Applicant had satisfied the (d)(1) test. Mr. Cooper stated that the Commission discussion underlying this finding considered the testimony of Applicant's witness Jackson regarding coal burn and coal contract buyout. Mr. Cooper testified that the evidence in the pending FAC 143 presents no legitimate basis for the Commission to attempt to reverse its decision in FAC 142 that the (d)(1) test had been satisfied.

Mr. Cooper also testified that the months of November and December 2023, which are in the reconciliation period for this FAC proceeding – are the relevant period impacted by this fuel supply contract change.

Mr. Cooper testified that the coal supply cost challenged by the OUCC was a prudently incurred cost and also showed it was the lowest cost option. Mr. Cooper discussed other cases where the Commission has previously allowed recovery of these types of costs, including coal contract amendment (buyout) costs, through the FAC.

Mr. Cooper concluded that these are fuel costs prudently incurred to optimize value for customers and manage inventory. He stated that on the basis of fuel cost alone, AES Indiana reduced costs for the benefit of customers by approximately $1.2 million by buying out the contract obligation. Mr. Cooper recommended the Commission approve Applicant's proposed fuel factor, including the challenged coal contract buyout costs. He testified these costs were prudently incurred and are reasonably reflected in this FAC, because this FAC is the proceeding reconciling the relevant months (November and December 2023) when these costs were incurred. He recognized that the Commission sometimes spreads the recovery of costs out over more than one FAC so as to mitigate significant rate impacts but said that the FAC factor impact here does not warrant its use. He said therefore, it is reasonable for the Commission to adhere to the regular FAC process where reconciliation of the relevant months is reflected in the factor approved in this FAC proceeding.

Substantial record evidence demonstrates the coal contract amendment costs challenged by the OUCC are fuel costs directly applicable to the acquisition of fuel and that these costs were reasonably incurred to implement a safe, efficient, and least expensive method for the acquisition and processing of fuel. In particular, Mr. Cooper's rebuttal testimony showed these costs were prudently incurred so AES Indiana could safely generate electricity. Safety is an important aspect of utility operations and was reasonably recognized by Applicant in its ongoing management of its fuel supply and generation of electricity.

The record also demonstrates that AES Indiana followed its Fuel Policy, approved in the Order for FAC 133, App. Ex. 4 at 7, 9. As shown by Confidential Attachment GAC-1R and explained by Mr. Cooper during the hearing (Tr. at 45), the actions taken by AES Indiana to amend its coal contract are expressly contemplated by the Fuel Policy approved by the Commission in FAC 133. App. Ex. 4 at 6. Entering into coal supply agreements and then managing delivery of coal is part of generating electricity. To conclude otherwise, fails to recognize how coal is delivered. As Mr. Cooper explained, coal is not a just-in-time delivered commodity and therefore is planned months and, in many cases, years in advance based on modeling of expected burn at the point in time purchase decisions are made.

The record shows the direct assignment of this expense to fuel cost aligns with the USOA. We find this expense was properly recorded to account 501 and is properly included in the corresponding FAC reconciliation months. Therefore, the Commission finds the cost challenged by the OUCC is eligible for FAC recovery. The record shows the challenged cost is a cost of fuel incurred by Applicant to generate electricity safely. Accordingly, the Commission rejects the OUCC proposal to exclude these costs from recovery. As discussed above, Applicant has shown its cost of fuel to generate electricity is in accordance with the FAC statute.

The Commission further finds substantial evidence demonstrates that the challenged costs were prudently incurred. In each FAC, AES Indiana presents extensive testimony on its efforts to procure fuel, including coal, and manage inventory and to do so in a way that optimizes the generation and purchase of power to provide electricity at the lowest cost reasonably possible. The OUCC testimony has regularly recommended AES Indiana update the Commission in FAC proceedings on coal inventory, projected coal burn and coal purchases, and the Commission's FAC orders have adopted this recommendation. The coal contract amendments challenged by the OUCC here were presented as part of AES Indiana's update in FAC 142. In particular, AES Indiana witness David Jackson testified that one of the ways Applicant is managing the coal pile is to amend contracts to defer tonnage and cancel coal shipments for a cost. The OUCC testimony in FAC 142 addressed this issue and the OUCC did not challenge the prudence of AES Indiana's actions. Rather, the OUCC recommended that recovery of the associated cost should be allocated to the relevant period impacted by the changes, which is what ASE Indiana did in this FAC 143 filing. In the FAC 142 Order, the Commission recognized Applicant's efforts:

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.

The Commission's Order in FAC 142 found AES Indiana satisfied the (d)(1) test. The evidence in this proceeding further demonstrates the process leading to the action taken by Applicant was logical, AES Indiana used good judgment, and reasonably relied on its Fuel Policy and planning techniques known at the time. As discussed above, the record shows the (d)(1) test has been satisfied.

Accordingly, the Commission finds substantial record evidence shows Applicant's proposed fuel factor, inclusive of the coal contract amendment costs, is ($0.003432) per kWh and this factor is approved. 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 $0.55 or 0.41% on the electric bill as compared to the factor currently in effect.

11. Confidential Information. On March 15, 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 March 26, 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 fuel cost factor, inclusive of the coal contract amendment costs, which is ($0.003432) 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: MAY 29 2024

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

Regina K. Joyner
Digitally signed by Regina K. Joyner
Date: 2024.05.29 10:14:53 -04'00'
on behalf of

Dana Kosco
Secretary of the Commission