ORIGINAL

Commissioner	Yes	No	Not Participating
Huston	√		
Freeman	√		
Krevda	√		
Ziegner	√		

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

APPLICATION OF INDIANAPOLIS POWER & LIGHT COMPANY D/B/A AES INDIANA FOR APPROVAL OF A FUEL COST FACTOR FOR ELECTRIC SERVICE DURING THE BILLING MONTHS OF SEPTEMBER 2022 THROUGH NOVEMBER 2022, IN ACCORDANCE WITH THE PROVISIONS OF I.C. 8-1-2-42, AND CONTINUED USE OF RATEMAKING TREATMENT FOR COSTS OF WIND POWER PURCHASES PURSUANT TO CAUSE NOS. 43485 AND 43740, AND CONTINUED RECOVERY OF THE COSTS OF THE FUEL HEDGING PLAN PURSUANT TO I.C. 8-1-2-42.	)	**CAUSE NO. 38703 FAC 136** **APPROVED: AUG 30 2022**

ORDER OF THE COMMISSION

Presiding Officers:
James E. Huston, Chairman
Stefanie N. Krevda, Commissioner
Loraine L. Seyfried, Chief Administrative Law Judge

On June 17, 2022, 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 2022 through November 2022 (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 17, 2022, 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 July 6, 2022.

On July 22, 2022, the Indiana Office of Utility Consumer Counselor ("OUCC") filed its report, direct testimony, and consumer comments.

An evidentiary hearing was held at 9:30 a.m. on August 11, 2022, in Room 222, PNC Center, 101 West Washington Street, Indianapolis, Indiana. At the hearing, Applicant and the OUCC appeared and participated by counsel. The testimony and exhibits of Applicant and the OUCC were admitted without objection.

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. 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, since certain matters will be subject to review in Cause No. 38703 FAC 133 S1 ("FAC 133 S1 subdocket"), we find Applicant has satisfied these requirements.

David Jackson, Director, Commercial Operations, AES US Services, LLC explained Applicant's participation in the Midcontinent Independent System Operator ("MISO") Open Access Transmission and Energy Markets Tariff, the projected fuel related MISO costs for the Forecast Period, and the true-up of fuel-related MISO costs and revenues during February 2022 through April 2022 (the "Historical Period"). Mr. Jackson also testified about the benefits to customers of Applicant's participation in MISO, where resources are centrally dispatched by MISO using simultaneous co-optimization.

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

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

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

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

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

Mr. Jackson testified Petersburg Units 2, 3, and 4 were offered as economic for most of the period. Mr. Jackson stated during the Historical Period all the weekly 7-day model runs showed positive margin for Petersburg Units 2, 3, and 4. He explained the units were offered as economic when available for dispatch, except for four days when Petersburg Unit 2 was shown as must run returning from outages. He provided further detail on the Petersburg unit commitment decisions during the Historical Period and explained AES Indiana ran a short-term model (which provides 30-day forward looks) to track the economic value of the Petersburg Units. He sponsored a copy of the model runs in Applicant's Exhibit 2-C, Confidential Attachment DJ-4. He added that non-economic factors were also considered in unit commitment decisions, including reliability, price certainty, operational needs, and avoidance of startup costs.

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

Mr. Jackson testified that Applicant considers both the long-term and short-term when making unit commitment decisions. He said the longer-term forecasts in each FAC are generated in a planning model that looks at the economic dispatch of the units on the day the model is run. He said as the future period becomes the actual period, the following drives commitment decisions: market pricing, protecting customers from price risk, operational issues, and reliability. In other words, he said Applicant makes unit commitment decisions based on circumstances as they exist during the actual period and assesses energy market decisions through a nearer-term forward-looking assessment. He said Applicant is continuing to improve its understanding of market conditions and costs associated with must run and other unit commitment decisions.

Mr. Jackson also updated the Commission on the short-term model Applicant implemented 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 coal units. He discussed how the model works, the inputs into the model, and additional considerations Applicant chose to apply to the model. He said the model output is captured on a spreadsheet showing a rolling 30-day period and the total profit and loss from each of the two types of trades. The total value of the two trades indicates if the unit is in or out of the money. He said Applicant began using the model at the end of May 2020 and continues to use it to support commitment decisions. He said Applicant will include model output from the Historical Period in the OUCC packet for review and will review the model and output with the OUCC during the audit.

Mr. Jackson also provided an update on Applicant's 2022 projected coal burn and coal purchases. Mr. Jackson stated Applicant's inventory is currently within its target range and Applicant continues to actively manage its inventory levels. He said Applicant expects to build coal inventory to the high side of its target range throughout 2022 to have appropriate supply for winter of 2022–2023. He noted Applicant's long-term coal contracts often contain some variability in the quantity of coal that Applicant can take under that particular contract. He said this allows Applicant to increase deliveries when coal burns go up and decrease deliveries when coal burns go down. He explained this contract variability is essential in managing the month-to-month variations in coal burns due to weather, market prices, and unit availability. However, he said this contract variability is limited and may not alone be sufficient to follow highly volatile coal demands. He explained that if coal demand were to change dramatically, Applicant would look to defer, delay, or leave certain open positions unfilled in a rapidly declining market, while looking to buy additional coal supplies in an upwardly moving market.

Mr. Jackson testified current market conditions have created an extremely tight coal market. More specifically, he explained a combination of high export demand and strong domestic coal burns along with coal producers struggling to add output to meet demand have led to scarcity in the coal markets. He said Applicant does not expect to experience issues with coal supply that impacted last winter based on current purchases and burn projections.

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

Mr. Jackson explained Applicant did not engage in peak power transactions during the Historical Period as a result of the Eagle Valley combined cycle gas turbine ("CCGT") outage. Instead, he said Applicant elected to purchase natural gas instead of peak power to reduce risk for customers. He testified that for the month of February 2022, Applicant purchased 70,000 MMBtu/day of physical natural gas as an alternative to purchasing peak power hedges of 257 MW per day. He said the physical natural gas hedges are deliverable to Harding Street to support generation or can be sold back versus gas daily index pricing if not economic at the time of realization. He said there were no hedge transactions for March or April 2022.

Mr. Jackson explained that when evaluating the benefit of using natural gas instead of purchased power, Applicant realized a savings of $1,148,630 in February 2022 for its customers. He said Applicant compared the natural gas hedge value and the value of the suggested power hedge, if it had been transacted, to validate which hedge would have provided the most benefit for Applicant's customers. He stated Attachment DJ-7 to Applicant's Exhibit 2 shows the decision to hedge natural gas instead of power created a $1,892,244 benefit for customers in February 2022.

Mr. Jackson also provided an update on the natural gas hedging transactions undertaken during the Historical Period. He explained how the physical natural gas hedges were used and explained why they were reasonable based on the facts and circumstances as they existed at the times the transactions were entered. He said that as explained in Cause No. 38703 FAC 122, the intent of the natural gas hedge is to mitigate customer exposure to natural gas price volatility. He testified the hedges achieve this objective by providing price certainty for power generation. More specifically, winter hedges protect from scarcity events and protect from price volatility associated with high demand periods. Additionally, he noted the natural gas hedges provide improved reliability of Applicant's natural gas fuel supply, lock in locational value fuel costs versus Henry Hub pricing, and reduce the need to purchase all of Applicant's natural gas requirements in the day-ahead and real-time natural gas markets, reducing the risk of volume-based pricing charges. For these reasons, Mr. Jackson concluded the hedges met their objectives. He said during the month of February 2022, Applicant did not see significant weather events or natural gas price volatility, but the market was vulnerable to the potential for price spikes related to early winter cold weather events. He stated as prices realized at lower values, additional gas for generation was purchased at lower market pricing.

Mr. Jackson also discussed the natural gas transactions for the Eagle Valley CCGT that were completed under the fuel hedging policy approved in Cause No. 38703 FAC 133. He stated Applicant initiated the Long-Term Hedging Program for Eagle Valley on March 28, 2022. He said once the plant was online and running as expected, Applicant moved expeditiously and in accordance with the hedging plan to bring hedged volumes in line with approved guidelines. He said Applicant expects to have all purchases made for the plan by the end of September 2022. Mr. Jackson sponsored Attachment DJ-9 to Applicant's Exhibit 2, which provides an evaluation of the hedges' economic settlement in April 2022 by comparing the hedge price to the daily index price for the natural gas delivery point associated with the hedges. He testified in the month of April

2022, hedges on gas represented a savings of $523,275. He explained Attachment DJ-10 of Applicant's Exhibit 2-C shows completed hedging transactions and remaining balances to be completed for the hedging policy approved in Cause No. 38703 FAC 133. He stated 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.

Finally, Mr. Jackson testified that in Cause No. 45493, Applicant committed to provide further information on its evaluation of the firmness needs for gas supply at the Harding Street Station in a future FAC filing. He said Applicant completed this evaluation and included as Attachment DJ-11 to Applicant's Exhibit 2-C.

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

Michael D. Eckert, Director of the OUCC's Electric Division, provided an update on the status of the Petersburg Units and when they were last called on by MISO to produce power. He testified Applicant's current coal inventory is within Applicant's target levels and indicated Applicant is actively looking at options to address its coal inventory. OUCC witness Gregory T. Guerrettaz, Certified Public Accountant, noted Applicant expressed concerns during the audit regarding the decreases in coal inventory level and the challenges of coal transportation. Mr. Eckert recommended Applicant update the Commission on its coal inventory and its 2023 projected coal burn and coal purchases in future FAC proceedings.

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

Mr. Eckert also discussed Applicant's purchased power hedging and stated the OUCC does not oppose the purchased power hedges.

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

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

Applicant also presented substantial evidence explaining Applicant did not engage in peak power transactions as a result of the Eagle Valley CCGT outage during the FAC 136 reconciliation period. Rather, Applicant elected to purchase natural gas instead of peak power to reduce risk for customers.

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 Witness Jackson, to be reasonable. Therefore, consistent with deferring the portion of the variance attributable to the Eagle Valley CCGT outage as proposed by Applicant, the Commission finds Applicant may include all hedging gains and losses, including any associated transactional costs, in the deferred amount. 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 and except with respect to the matters subject to review in the FAC 133 S1 subdocket, the Commission finds Applicant has made every reasonable effort to acquire fuel and generate or purchase power to provide electricity at the lowest fuel cost reasonably possible.

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

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

Based upon the evidence, the Commission finds Applicant's treatment of the ASM charge types and other fuel-related MISO costs and revenues is consistent with the Commission's Phase II, FAC 85, and FAC 97 Orders, and is approved. The Commission further finds Applicant's recovery of RSG Charges 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. Jackson explained that each day, a benchmark is established based upon a generic Gas Turbine ("GT"), using a generic GT heat rate of 12,500 btu/kWh and the day ahead natural gas prices for the New York Mercantile Exchange ("NYMEX") Henry Hub, plus a $0.60/MMBtu gas transport charge for a generic gas-fired GT (together, the "Benchmark"). He explained that Applicant continues to follow the guidelines and procedures established in the Purchased Power Order. He stated that purchases made in MISO's economic dispatch regime to meet jurisdictional retail load are a cost of fuel and recoverable in the utility's FAC up to the actual cost or the Benchmark, whichever is lower.

Mr. Jackson testified Applicant incurred a total of $498,872 of purchased power costs over the applicable Benchmarks during the Historical Period. He said Applicant makes power purchases when economical or due to unit unavailability. Mr. Jackson testified that consistent with the Purchased Power Order, Applicant has an opportunity to request recovery and justify the reasonableness of purchased power costs above the applicable Benchmark.

Applicant provided a summary of the purchased power volumes, costs, total of hourly purchased power costs above the applicable Benchmarks during the Historical Period, and the reasons for the purchases at-risk after consideration of MISO's economic dispatch. Mr. Jackson testified that utilizing the methodology approved in the Purchased Power Order, no amount of the purchased power is non-recoverable during the applicable accounting period. However, Applicant proposes to include only the non-outage portion of the purchases over the Benchmark of $205,516. Mr. Jackson said the forced outage related purchases over the Benchmark will be considered in the resolution of the pending FAC 133 S1 subdocket. Additionally, he noted removing the seasonal capacity megawatts of the Eagle Valley CCGT from the megawatts for units with full forced outage results in $972 of purchased power over the Benchmark that is non-recoverable. Mr. Jackson testified these total purchased power costs during the Historical Period are reasonable.

Mr. Eckert explained the purchased power over the Benchmark treatment is controlled by the Purchased Power Order and Applicant followed the guidelines and procedures established in that Order. He stated the OUCC calculated the same amount of purchased power over the Benchmark as Applicant. He stated that AES Indiana is proposing to exclude from the factor the outage-related portion of the purchases over the Benchmark of $293,356. He further testified that while he determined Applicant performed the calculation correctly, the OUCC is concerned that Applicant did not determine if the CCGT outage was a result of "imprudence, malfeasance, nonfeasance, or other inappropriate acts" in accordance with the Purchased Power Order. He stated therefore, the OUCC recommends that final resolution of the recoverability of the $498,872 in purchased power over the Benchmark be deferred to the FAC 133 S1 subdocket.

In rebuttal, AES Indiana witness Jackson clarified that not all the purchased power over the Benchmark is attributable to the forced outage that is being reviewed in the pending FAC 133

S1 subdocket, noting that only $293,356 of the amount identified by Mr. Eckert is attributable to the forced outage.

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. However, as noted by the OUCC, adherence to a portion of the guidelines and procedures remains in question. Accordingly, the Commission finds that the recoverability of the outage related portion of the $498,872 in purchased power over the Benchmark will be determined in the FAC 133 S1 subdocket.

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 April 30, 2022. She stated that Applicant's actual return is less than its authorized return for the 12 months ending April 30, 2022. 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, 2022) less than that granted in its last general rate proceeding, as adjusted for applicable Environmental Compliance Cost Recovery and Transmission, Distribution, and Storage System Improvement Charge proceedings.

In rebuttal, AES Indiana updated the Earnings Test Summary for the FAC 135 period and explained that this revision does not result in a change in the proposed FAC factor but is included so that the record can reflect the change.

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, 2022. Thus, as reflected in Applicant's Exhibit 1, Attachment NHC-3, Applicant has an authorized return of $228,291,000 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, 2022, was $223,712,000. Therefore, the Commission finds that during the 12-month period ending April 30, 2022, Applicant did not earn a return in excess of its authorized return in compliance with the statutory requirements of Ind. Code § 8-1-2-42(d)(3).

8. **<u>Estimating Techniques</u>.** Ind. Code § 8-1-2-42(d)(4) requires the Commission to find a utility's estimate of its prospective average fuel costs for each month of the estimated three calendar months is reasonable after taking into consideration the actual fuel costs experienced and the estimated fuel costs for the three calendar months for which actual fuel costs are available. According to Applicant's Exhibit 1, Attachment NHC-1, Schedule 5, page 4 of 4, Applicant's weighted average deviation between forecast and actual fuel cost was a negative 17.75% for the Historical Period. Ms. Coklow explained while Applicant has calculated this difference, it has not included fuel cost variances for the portion attributable to the Eagle Valley Outage at this time in the mitigated factor calculation proposed in this proceeding.

Mr. Jackson explained the largest driver of the variance was the increase in natural gas prices. He said the increase in natural gas price elevated market prices of purchased power. Mr. Jackson provided further detail regarding natural gas prices during the Historical Period.

Mr. Jackson stated natural gas prices have increased significantly, 288% higher, for the Forecast Period, versus the same forecast period one year ago. He said the key drivers of this increase are uncertainty of domestic supply and increased demand. He said natural gas production has been slow to respond to higher prices and demand from electric generation has been high. Further, he said export demand in the liquefied natural gas market remains robust. He added that the war between Russia and Ukraine continues to support higher natural gas and coal prices due to concern of global supply interruption and trade embargos on Russian commodities.

Mr. Guerrettaz stated the OUCC performed a detailed review of Applicant's estimation model and noted the forecast had the following items affecting it: (1) daily changes in the price of natural gas; (2) daily changes of power prices for the MISO market; (3) recent hedges put into place; and (4) Applicant's coal inventory issues.

Mr. Guerrettaz stated Applicant provided an updated Fuel ÷ Sales during the audit, which showed a projected Fuel ÷ Sales of 47.840 Mills per KWh. Mr. Guerrettaz and Mr. Eckert said the OUCC proposes to calculate the factor using the updated Fuel ÷ Sales and that each variance component be spread over a six-month period. Mr. Guerrettaz said the first reason for this proposal is the projected Fuel ÷ Sales in the Application is the highest ever for AES Indiana and the second reason is the natural gas and purchased power prices have decreased as a result of events in the gas markets. Mr. Eckert added that spreading the variance over a six-month period will provide customers with temporary but tangible relief. Mr. Eckert also said AES Indiana indicated it agrees with the proposal to use the updated forecast; however, AES Indiana does not agree to spread the variance over six months.

In rebuttal, AES Indiana witness Jackson stated that Applicant continues to be unopposed to basing the factor on the updated forecast but noted that Applicant's position is subject to the clarifications presented in his rebuttal testimony regarding fuel cost trends. Mr. Jackson said the

July 8, 2022 forecast the OUCC proposes to use reflects an isolated point in time and since the date of that forecast, costs have trended upward and returned to very near the levels at the time the originally proposed FAC factor was developed. He said that if the FAC factor were to be based on the more recent market date, the forecast Fuel ÷ Sales would be $53.23 as compared to the OUCC's proposed factor $47.84. In her rebuttal, AES Indiana witness Coklow said using the same forecast Fuel ÷ Sales that the OUCC proposed in its testimony results in a decrease of $5.602 Mills/kWh from the previous forecast Fuel ÷ Sales of $53.442. Noting Mr. Jackson's rebuttal testimony regarding fluctuating market conditions, she said that when forecast Fuel ÷ Sales is lower or higher than costs actually incurred, the resulting variances to be addressed in a future FAC filing can be significant.

While we further discuss the calculation of the factor and treatment of the variance below, based upon the evidence, we find Applicant's estimating techniques are reasonably accurate and its estimate of fuel costs for the Forecast Period is accepted.

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

Mr. Jackson said Hoosier and Lakefield are both Dispatchable Intermittent Resources in the MISO market and can ramp quickly, largely avoiding negative locational marginal prices. He stated curtailed power is billable when certain criteria are met. He said the level of curtailments at Lakefield were higher than the level of curtailments experienced during the time period covered by FAC 135, and lower than the time period experienced one year ago (in Cause No. 38703 FAC 132).

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

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

10. <u>Reconciliation and Resulting Fuel Cost Factor for Electric Service</u>. According to Applicant's Exhibit 1, Attachment NHC-1, Schedule 1, Applicant's total estimated cost of fuel for the Forecast Period is $160,736,031, and its total estimated sales are 3,007,656 kWh. Applicant's estimated cost of fuel, after taking into consideration the proposed reconciliation component, is $0.07796 per kWh. Ms. Coklow discussed in detail how the mitigated FAC factor was calculated. The evidence of record indicates Applicant has included the remaining uncollected portion of the FAC 133–FAC 135 variances it calculated as not attributable to the Eagle Valley

CCGT outage totaling $34,140,968, which was approved for recovery in FAC 135. In addition, she said for mitigation purposes Applicant is proposing to defer in this FAC the total fuel cost variance for the Historical Period attributable to the Eagle Valley outage equaling an estimated $6,350,096. Ms. Coklow stated the mitigated factor is proposed to recognize the impact of increased natural gas and coal prices on overall fuel costs. Ms. Coklow stated that, in addition, this proposal will allow the price for the electric service to more timely reflect the actual cost of service.

Ms. Coklow testified Applicant is seeking authority to continue deferring as a regulatory asset the variances calculated during the Historical Period attributable to the Eagle Valley CCGT outage (equaling an estimated $6,350,096) for recovery in a future FAC filing or pending conclusion of the FAC 133 S1 subdocket.

As shown on Schedule 1 of Attachment NHC-1 to Applicant's Exhibit 1, when the adjusted fuel cost charge is reduced by the base cost of fuel, the result is the proposed mitigated fuel factor of $0.037858 per kWh for the Forecast Period's billing cycles. Ms. Coklow provided a comparison between the proposed interim factor and the unmitigated calculated factor. She testified the unmitigated factor would result in an increase of $26.50 or 20.53% for an average residential customer using 1,000 kWh per month. In relation to the factor currently in effect, the mitigated factor will result in an increase of $24.39 or 18.90% for an average residential customer using 1,000 kWh per month.

Applicant proposes the mitigated factor would follow the normal reconciliation process and would be reconciled and trued-up as part of the Cause Nos. 38703 FAC 137 and 138 filings. To the extent that the amount attributable to the outage differs upon the subdocket outcome, these factors would be subject to reconciliation and true-up in a future FAC filing upon resolution of the subdocket.

On rebuttal, Ms. Coklow testified that Applicant is not entirely in agreement with the OUCC's proposal to spread recovery of the total variances. She said Applicant proposes a compromise to balance the desire to mitigate impact on the customer with the need to recognize market conditions in the factor. She said Applicant proposes that the total estimated non Eagle Valley outage variance for the FAC 136 reconciliation period of $18,054,560 be spread over two FAC periods while the remaining 50% variance from FAC 135 in this Cause be collected over one period. She said this is reasonable because the treatment of the FAC 135 variances was already decided in FAC 135 and the collection of the remaining variance should not be delayed further. She added that the variance is driven by large increases in natural gas and power costs and the OUCC's proposed factor would not reflect the larger variances experienced due to increased fuel prices. Ms. Coklow added that while the OUCC's proposal mitigates customer rate impact it masks market conditions at the time of this rebuttal filing (as discussed by Witness Jackson) and thus does not send an appropriate price signal to customers regarding the actual cost of electricity usage. Ms. Coklow also explained that spreading variances impacts Applicant because it funds near term cash working capital shortfall from under-collected fuel and purchased power costs through incremental short-term borrowings which have a borrowing ceiling; continuing to spread under-collection results in increased borrowings which leads to higher interest expense and reduced liquidity, which ultimately result in increased costs to customers.

Ms. Coklow said Applicant's proposal to spread the FAC 136 period variance over two FAC filings and the remaining FAC 135 variance over one filing will provide rate relief for customers while limiting the period of time customers will be impacted by the under-collection. She said using Applicant's proposal, the FAC factor would decrease from the original proposed factor of $37.858 to a factor of $29.255 for a decrease of $8.60 or 23%. Finally, Ms. Coklow discussed the Commission's decision in *Duke Energy Indiana*, Cause No. 38707 FAC 132 (IURC 6/28/2022), explaining why Applicant's, and not the OUCC's, proposal is consistent with this decision. Ms. Coklow said in relation to the FAC 135 factor, the FAC 136 rebuttal factor would result in an increase of $15.79 or 12.23%. She said the original FAC 136 proposed factor would have resulted in an increase of $24.39 or 18.90% from the FAC 135 factor currently in place.

At the evidentiary hearing in this Cause, the OUCC advised the Commission that Applicant's proposal on rebuttal is acceptable to the OUCC.

The Commission approves the proposed fuel factor of $0.029255 on an interim basis, subject to reconciliation and true-up in a future FAC filing, or upon resolution of the recoverability of the fuel and purchased power costs attributable to the Eagle Valley outage pending in the FAC 133 S1 subdocket. 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. The approved factor reflects Applicant's proposal to exclude outage related variances for FAC 136 and defer these costs as a regulatory asset balance for recovery pending conclusion of the FAC 133 S1 subdocket. The Commission further grants Applicant accounting authority to continue deferring as a regulatory asset the variances calculated during the reconciliation period of May 2021 through March 2022 attributable to the Eagle Valley outage, subject to reconciliation and true-up as stated above.

11. Confidential Information. On June 17, 2022, Applicant filed a Motion for Protection and Nondisclosure of Confidential and Proprietary Information in this Cause, which was supported by an affidavit from Mr. Jackson showing that certain information to be submitted to the Commission was trade secret information as defined in Ind. Code § 24-2-3-2 and should be treated as confidential in accordance with Ind. Code §§ 5-14-3-4 and 8-1-2-29. In a July 6, 2022 Docket Entry, the Presiding Officers found the information should be held confidential on a preliminary basis, after which the information was submitted under seal. After review of the information and consideration of the affidavit, we find the information is trade secret information as defined in Ind. Code § 24-2-3-2, is exempt from public access and disclosure pursuant to Ind. Code §§ 5-14-3-4 and 8-1-2-29, and shall be held as confidential and protected from public access and disclosure by the Commission.

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

1. Applicant's mitigated fuel cost factors as calculated and discussed at Finding Paragraph No. 10 above are approved on an interim basis, subject to reconciliation and true-up in a future FAC filing, or upon resolution of the Eagle Valley CCGT forced outage matters pending in the FAC 133 S1 subdocket.

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 include all gains or losses, including any associated transactional costs, of its fuel hedging plan in the variance deferral amount subject to the conditions of this Order.

5. Applicant is granted all necessary accounting authority to defer as a regulatory asset the total fuel cost variance for the reconciliation period of May 2021 through March 2022 attributable to the Eagle Valley CCGT outage, for recovery in a future FAC filing or pending conclusion of the FAC 133 S1 subdocket.

6. The impact of the Eagle Valley CCGT outage on fuel costs will be examined in the FAC 133 S1 subdocket, and the recovery of such fuel costs herein is interim subject to refund pending the outcome of the FAC 133 S1 subdocket.

7. Applicant shall update the Commission on how it proposes to address its coal inventory and its 2023 projected coal burn and coal purchases.

8. 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.

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

HUSTON, FREEMAN, KREVDA, AND ZIEGNER CONCUR:

APPROVED: AUG 30 2022

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

Dana Kosco Digitally signed by Dana Kosco
Date: 2022.08.30 14:29:22 -04'00'

Dana Kosco
Secretary of the Commission