ORIGINAL

Commissioner	Yes	No	Not Participating
Swinger	√		
Bain	√		
Deig			√
Jerrells	√		
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 2026, OCTOBER 2026, AND NOVEMBER 2026, 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 NO. 43740, AND CONTINUED RECOVERY OF THE COSTS OF THE FUEL HEDGING PLAN PURSUANT TO I.C. 8-1-2-42.	)	**CAUSE NO. 38703 FAC 152** **APPROVED: AUG 26 2026**

ORDER OF THE COMMISSION

Presiding Officers:
David E. Ziegner, Commissioner
Kristin E. Kresge, Administrative Law Judge

On June 12, 2026, Indianapolis Power & Light Company d/b/a AES Indiana ("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 through November 2026 (the "Forecast Period"); (2) the continued use of ratemaking treatment for the cost of wind power purchases pursuant to Cause No. 43740; and (3) approval of a fuel hedging plan and continued authority to recover the costs of its fuel hedging plan. AES Indiana concurrently filed a Motion for Protection and Nondisclosure of Confidential and Proprietary Information, which was granted on a preliminary basis by Docket Entry dated July 1, 2026.

On July 17, 2026, the Indiana Office of Utility Consumer Counselor ("OUCC") filed its direct testimony. On July 27, 2026, AES Indiana filed its rebuttal testimony.

An evidentiary hearing was held at 9:00 a.m. on August 11, 2026, in Room 222, PNC Center, 101 West Washington Street, Indianapolis, Indiana. AES Indiana and the OUCC appeared and participated by counsel. The parties' evidence was admitted into the record without objection.

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

1. **Notice and Jurisdiction.** Notice of the evidentiary hearing was given and published by the Commission as required by law. AES Indiana 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 AES Indiana's fuel cost charge, the ratemaking treatment of its wind power purchase costs and costs associated with a natural gas hedging plan. Therefore, the Commission has jurisdiction over AES Indiana and the subject matter of this Cause.

2. **AES Indiana's Characteristics.** AES Indiana is an electric generating utility and a corporation organized and existing under Indiana law with its principal office in Indianapolis, Indiana. AES Indiana is engaged in rendering electric public utility service in Indiana. AES Indiana 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.** AES Indiana 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 reasonably possible fuel cost. As discussed below, we find AES Indiana has satisfied these requirements.

A. **Efforts to Acquire Fuel.** Alexander Dickerson, Director, Trading and Asset Management, explained AES Indiana'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 through April 2026 ("Historical Period"). Mr. Dickerson also testified about the customer benefits from AES Indiana's participation in MISO, where resources are centrally dispatched by MISO using simultaneous co-optimization.

Mr. Dickerson supported AES Indiana's purchases of coal, fuel oil, and natural gas for use in its generating stations. He testified that AES Indiana's Harding Street Station and Petersburg Generating Station ("Petersburg") manage their fuel oil purchases based on inventory set-points and regional market index pricing. He explained that AES Indiana currently has contracts with one coal producer and receives coal from one mine. Mr. Dickerson stated that AES Indiana verifies the reasonableness of its coal cost by using a competitive bidding process to award its coal contracts. Mr. Dickerson stated that as Petersburg Units 3 and 4 go into their conversion outages in 2026, AES Indiana has entered into contracts that will allow enough flexibility to ensure adequate supply, at the lowest fuel cost reasonably possible, while also managing the coal inventory to avoid purchasing more volume than reasonably needed.

Mr. Dickerson also testified regarding AES Indiana's unit commitment process. He stated AES Indiana 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 restart the unit is also considered. Additionally, he testified AES Indiana 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, AES Indiana maintains a generation mix that includes coal, natural gas, and renewables. He explained AES Indiana raises the minimum operating level when required to maintain reliability or for other operational reasons. He testified that under normal conditions, AES Indiana 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 stated 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 testified 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 that AES Indiana 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 AES Indiana'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, noting that Petersburg Unit 3 and Unit 4 were offered as must run, economic, and outage. He stated periods of must run were due to operational needs of the units, including management of the coal inventory at safe levels and contractual requirements for coal delivery, as well as expected positive margin. He explained periods of outage were due to both scheduled and forced outages. Mr. Dickerson testified that AES Indiana evaluated weekly model runs for commitment decisions and that, overall, AES Indiana's operation of the Petersburg units was reasonably aligned with market prices.

Mr. Dickerson provided further detail on the Petersburg unit commitment decisions during the Historical Period and explained AES Indiana ran a short-term model (which provides 30-day forward looks) to track the economic value of the Petersburg units. He sponsored a copy of the model runs in Petitioner's Exhibit No. 2-C, Confidential Attachment AD-3. He added that noneconomic factors were also considered in unit commitment decisions, including reliability, price certainty, operational needs, and avoidance of startup costs.

Mr. Dickerson stated AES Indiana 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, AES Indiana acknowledges that a look-back analysis can inform its decision-making on a going forward basis and support AES Indiana's ongoing effort to improve its modeling and decision process.

Mr. Dickerson testified that AES Indiana considers both the long-term and short-term when making unit commitment decisions. He stated 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 testified that 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 stated, AES Indiana 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 stated AES Indiana 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 AES Indiana began using in May 2020 improves the economic view of unit commitment on a rolling four-week period and said still important are noneconomic factors, such as predicted strong weather/high loads (hedge value), operational issues, and reliability, which will continue to be considered must run decisions.

Mr. Dickerson also updated the Commission on the short-term model AES Indiana uses to support and track the Petersburg unit commitment decisions. He stated 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 testified 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 runs at a positive margin during a given timeframe. He testified AES Indiana 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 AES Indiana's projected coal burn, coal purchases, and coal inventory management activities. Mr. Dickerson stated due to the colder than normal winter and continued higher natural gas prices the coal inventory has decreased. He testified AES Indiana's coal inventory is currently below the 25-50 day supply of coal inventory target range as AES Indiana gets closer to the natural gas conversion outage on Unit 4.

Mr. Dickerson testified that AES Indiana continues to actively manage its inventory levels and is tracking towards minimizing any leftover coal once Unit 4 goes into outage. He explained the efforts AES Indiana is taking, including hiring a third-party engineering firm to conduct drone surveys to ensure usable coal is recovered as well as density core sampling to determine depth of usable coal. AES Indiana anticipates that some unrecoverable coal will remain following these efforts. He stated, for example, coal at the bottom of the pile may contain rocks, sticks, mud, and other materials. In addition, he explained some coal at the edges of the coal pile and near structures may not be safely and/or economically reclaimed. Mr. Dickerson stated this is an unavoidable and expected consequence of acquiring, storing, and burning coal over a long period of time. He stated because the exact amount of remaining coal is not known at this time, AES Indiana has not included an adjustment for the unrecoverable inventory in the FAC 152 Forecast Period. Rather, AES Indiana anticipates to address any necessary adjustment as part of the reconciliation in a future FAC. He stated recognizing any remaining coal that cannot be economically or safely recovered as a fuel expense is consistent with how such costs were reflected in AES Indiana's prior FACs where such inventory adjustments were reflected as fuel expense and recovered through the FAC.

Mr. Dickerson noted AES Indiana's coal contracts contain some variability in the quantity of coal that AES Indiana can take under a particular contract. He stated this allows AES Indiana to decrease deliveries when coal burns go down or increase them when burns go up. 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. Finally, Mr. Dickerson testified there is no decrement pricing in the Forecast Period.

Mr. Dickerson discussed the natural gas transactions for the Eagle Valley combined-cycle gas turbines that were completed under the current Fuel Hedging Policy. Mr. Dickerson sponsored Attachment AD-5, to AES Indiana's Exhibit No. 2, which provides an evaluation of the hedges' economic settlement in the Historical Period, by comparing the hedge price to the daily index price for the natural gas delivery point associated with the hedges. He testified that in the month of February 2026, hedges on natural gas represented a cost of $3,879,203. Hedges on natural gas in the month of March 2026 represented a cost of $7,296,420, and in the month of April 2026, hedges on natural gas represented a cost of $6,725,837. *Id.* at 28. He stated as an additional hedge, AES Indiana entered a physical power purchase for February, which settled at a cost of $193,005.

Mr. Dickerson explained that natural gas hedges were transacted through 2024, and into the latter half of 2025. He stated natural gas production remained at high levels coming into the winter and United States storage inventory reached a peak of 3.95 Tcf, which is near the theoretical max. He explained winter started cold but quickly turned mild up until Winter Storm Fern at the end of January. He stated natural gas prices had declined through the winter as risk premium was eliminated. However, he testified during Winter Storm Fern prices spiked significantly as the cold swept across much of the country setting record lows. He stated as soon as Winter Storm Fern was over, gas prices went back down and have remained below $3/MMBtu in the cash market. He stated this trend continued through April 2026 as the carry-out inventory from the winter was above 2.0 Tcf, setting up favorably for next winter.

Mr. Dickerson testified regarding the benefits to customers of AES Indiana's long-term hedging program. He explained that AES Indiana developed the long-term hedging program to achieve three primary goals for its customers. He stated the first goal was to increase the reliable delivery of natural gas to all gas-fired generation in AES Indiana's fleet. He explained this is achieved through owning firm transportation as well as purchasing third-party delivered gas to Eagle Valley off the Rockies Express pipeline. He stated that by utilizing third party firm capacity to deliver to Eagle Valley, more of AES Indiana's Texas Gas and REX firm capacity can be utilized at the Harding Street Station. He testified that this enhances the firm transportation portfolio of AES Indiana to provide reliable fuel delivery. Mr. Dickerson stated the second goal of purchasing Rockies Express volumes delivered to Eagle Valley is due to the historical volatility of Rockies Express Zone 3 pricing. He testified by locking in a fixed price, that volatility is mitigated for those volumes. He testified that the third and final goal of the program is to reduce the price volatility that is inherent within the natural gas market. He testified as part of the hedging program approved in Cause No. 38703 FAC 145, AES Indiana is taking a more holistic portfolio view of hedging and has expanded the areas in which gas purchases are made. 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 stated these benefits to customers are focused on risk reduction - creating more predictable pricing and increasing reliability of physical gas delivery. He explained as the new hedging policy is enacted the portfolio will be hedged holistically against retail load. He testified this will allow for a more diverse hedging strategy including Rockies Express, Texas Gas Transmission, power, and coal. He stated the three primary goals will remain the same, however the third goal will be further enhanced by the flexibility of diverse hedging options.

Mr. Dickerson next testified regarding firm transportation costs incurred by AES Indiana. He stated that the cost of gas generation contains the delivered cost of natural gas, including firm transportation costs. He stated AES Indiana works to prudently reserve firm transportation capacity to ensure its natural gas-fired units have reliable gas service. He explained that this is necessary and prudent to ensure the units are available and have the reliable fuel service needed for critical days. He explained the transportation costs reserve space on the pipelines that provide the fuel for AES Indiana's plants and allow AES Indiana to more efficiently reach high supply areas or more heavily traded points. He stated at the same time, AES Indiana looks for opportunities to work with third-party marketers to release capacity where practicable to achieve additional value for AES Indiana's customers, as has been done in previous FACs. He stated to the extent AES Indiana is able to achieve additional monetary value from releasing capacity or through the Asset Management Agreement ("AMA"), such revenues flow through the FAC to offset other fuel costs.

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, a Chief Technical Advisor within 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 regarding AES Indiana's current coal inventory and acknowledged AES Indiana is actively managing its inventory to minimize its remaining coal inventory when Petersburg Unit 4 is taken offline. Mr. Eckert recommended AES Indiana provide an update on its coal inventory and its 2026 projected coal burn and coal purchases in future FAC proceedings.

Mr. Eckert noted that Mr. Dickerson provided the results of AES Indiana's natural gas hedging program and stated additional information was provided during the OUCC's FAC audit. He recommended AES Indiana continue to file the results of its natural gas hedging program in each subsequent FAC, provide an analysis of the facts and circumstances existing when the transactions were entered into, and provide copies of its hedging program in future FAC proceedings, if revised.

OUCC Witness Gregory T. Guerrettaz, CPA and President of Financial Solutions Group, Inc., testified the OUCC discussed the implementation of AES Indiana's fuel procurement policy covering natural gas hedging policy with AES Indiana. He further recommended that AES Indiana include any AMA credits that are fixed, known, and measurable in its forecast process.

In rebuttal, Natalie Herr Coklow, Director in the Regulatory Accounting department of AES US Services, LLC, testified that as part of the AMA that AES Indiana entered into in April

2026, 100% of the optimization revenue that AES Indiana receives is flowed back to its customers through the FAC. She noted there are portions of the optimization revenue that result from various hedge opportunities and are paid to AES Indiana as the hedge is realized. She said the hedges will be included in the FAC when their positions are realized. She stated to the extent such future AMA revenue credits are fixed, known, and measurable at the time of AES Indiana's FAC filing, they will be included in AES Indiana's FAC forecasting process. Otherwise, such credits would be reflected in the reconciliation.

AES Indiana presented substantial evidence regarding its unit commitment decision-making process that shows AES Indiana considers both short-term and long-term vantage points. While economics do not capture all the reasons for unit commitment, we find the modeling will help AES Indiana support its decision-making. We further find that price risk, reliability, and operational needs are also reasonably factored into AES Indiana's decision process. Summer and winter periods create different challenges, including the potential for high price events that prompt unit commitment decisions to consider more than purely economic factors. Accordingly, substantial evidence demonstrates, and we find, that AES Indiana'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. We further find the inclusion of firm transportation costs and fuel management software costs incurred by AES Indiana to be reasonable. The record shows AES Indiana works to prudently reserve firm transportation capacity to ensure its natural gas-fired units have reliable gas service. The record further shows AES Indiana looks for opportunities to work with third-party marketers to release capacity where practicable to achieve additional value for customers. To the extent AES Indiana is able to achieve additional monetary value from releasing capacity or through the AMA, such revenues flow through the FAC to offset other fuel costs. We find reasonable and approve AES Indiana's proposal to either reflect such AMA credits in the FAC forecast process when fixed, known, and measurable, or to otherwise reflect such credits in the reconciliation.

AES Indiana also presented substantial evidence regarding the results of its natural gas hedging program. The record shows AES Indiana's hedging analysis is consistent with the process used to inform hedge decisions for the financial power hedges entered during previous FAC proceedings. The OUCC did not oppose AES Indiana's hedges, and we find AES Indiana's purchased power hedges, including the purchase of natural gas discussed by AES Indiana's Witness Dickerson, to be reasonable; therefore, the Commission finds the incurred gains or losses are reasonable and recoverable through the FAC. AES Indiana shall continue to provide in its next FAC the information the OUCC recommended regarding AES Indiana's hedging program.

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

B. 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 AES Indiana continues to follow the guidelines and procedures established in the Purchased Power Order. He stated purchases made in MISO’s economic dispatch regime to meet jurisdictional retail load are a cost of fuel and recoverable in the utility’s FAC up to the actual cost or the Benchmark, whichever is lower.

Mr. Dickerson testified AES Indiana incurred a total of $995,506 of purchased power costs over the applicable Benchmarks during the Historical Period. He stated AES Indiana makes power purchases when economical or due to unit unavailability. Mr. Dickerson testified that consistent with the Purchased Power Order, AES Indiana has an opportunity to request recovery and justify the reasonableness of purchased power costs above the applicable Benchmark.

Mr. Dickerson testified that utilizing the methodology approved in the Purchased Power Order, all but $399 of AES Indiana’s purchased power costs for the applicable accounting period is recoverable. He explained that more than half of the purchased power above the benchmark occurred between February 3 and 6, 2026. He said while AES Indiana had a forced outage at Eagle Valley due to a Steam Line Repair, AES Indiana also had units available that were not called upon by MISO, resulting in several hours of purchased power above the benchmark and economic purchases from the market.

Mr. Eckert explained the purchased power over the Benchmark treatment is controlled by the Purchased Power Order, and he testified that AES Indiana followed the guidelines and procedures established in that Order.. He confirmed that his calculations yielded the same amount of purchased power over the Benchmark as AES Indiana provided. He recommended the Commission allow AES Indiana to recover $995,107 in purchased power over the benchmark.

Based on the evidence, we find AES Indiana’s identified purchased power costs were reasonable under the circumstances at the time of the purchases and are approved.

4. <u>MISO Market Related Activity</u>. Mr. Dickerson testified that AES Indiana’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 AES Indiana 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”), AES Indiana has included Demand Response Resource Uplift charges from MISO in its cost of fuel in this proceeding. Further, he testified that consistent with the Commission’s Order in Cause No. 38703 FAC 85 (“FAC 85 Order”), AES Indiana 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 AES Indiana’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 AES Indiana’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 AES Indiana’s Exhibit No. 2, Attachment AD-1.

Mr. Eckert testified that AES Indiana's proposed ratemaking treatment for the ASM charge types is consistent with the Commission's approved ratemaking treatment in the Phase II Order.

Based upon the evidence, the Commission finds AES Indiana's treatment of the ASM charge types and other fuel-related MISO costs and revenues is consistent with the Commission's Phase II, Order and its Orders issued in Cause Nos. 38703 FAC 97 and 38703 FAC 85, and is approved. The Commission further finds AES Indiana's recovery of RSG Payments is consistent with the June 3, 2009 Order in Cause No. 43664 and is approved.

5. **Operating Expenses.** Ind. Code § 8-1-2-42(d)(2) requires the Commission to find that the utility's actual increase 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 Petitioner's Exhibit No. 1, Attachment NHC-2 calculates the Ind. Code § 8-1-2-42(d)(2) test, showing total jurisdictional operating expenses excluding fuel costs have increased.

Mr. Guerrettaz agreed AES Indiana did not have decreases in other operating costs that could be used to offset fuel cost increases.

Based on the evidence, the Commission finds AES Indiana'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).

6. **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 Petitioner's Exhibit No. 1, Attachments NHC-3 and NHC-4, which calculate the Ind. Code § 8-1-2-42(d)(3) test, show AES Indiana's actual return for the 12 months ending April 30, 2026. She stated that AES Indiana's actual return was more than its authorized return for the 12 months ending April 30, 2026; however, the sum of AES Indiana's differentials for the relevant period is less than zero. Accordingly, she stated no reduction in the fuel factor is required, and the Commission should find the return test of Ind. Code § 8-1-2-42(d)(3) is satisfied.

Mr. Guerrettaz agreed AES Indiana had jurisdictional net operating income (for the 12 months ending April 30, 2026) greater than the prorated allowed return as adjusted for various applicable trackers. He stated because the sum of differentials for the relevant period is a negative $374,624,000 no adjustment to the factor is recommended.

Upon our consideration of the record evidence, the Commission finds AES Indiana has properly determined the authorized operating income for the 12 months ending April 30, 2026. Thus, as reflected in Petitioner's Exhibit No. 1, Attachment NHC-3, AES Indiana has an authorized return of $313,369,000 for purposes of this proceeding. Attachment NHC-2 to Petitioner's Exhibit No. 1 (lines 12-14) calculates the Ind. Code § 8-1-2-42(d)(3) test, which shows that AES Indiana's actual return for the 12 months ending April 30, 2026, was $332,986,000. However, as shown on Attachment NHC-4 to Petitioner's Exhibit No. 1, the sum of differentials for the relevant period is less than zero. Therefore, the Commission finds that during the 12-month period ending April 30, 2026, AES Indiana has satisfied the statutory requirements of Ind. Code § 8-1-2-42(d)(3).

7. **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 Petitioner's Exhibit No. 1, Attachment NHC-1, Schedule 5, page 4 of 4, AES Indiana's weighted average deviation between forecast and actual fuel costs was an overestimate of 4.69% for the Historical Period.

Mr. Dickerson stated February 2026, March 2026, and April 2026 deviations of actual to forecast F/S were 4.98%, 7.04%, and 2.52%, respectively. He stated February, March, and April saw lower than forecast generation from coal. He explained gas and power prices realized in line with the forecast, and that the mild weather through the Historical Period resulted in lower demand and therefore lower than forecasted generation and fuel expense.

Mr. Dickerson compared the forecasted natural gas costs for the Historical Period to realized Henry Hub values. He stated the February 2026, March 2026, and April 2026 Indianapolis temperature variance from normal were +2.6 degrees, +8.2 degrees, and +6.8 degrees, respectively.

Mr. Guerrettaz stated the OUCC performed a detailed review of AES Indiana's estimation model, and he noted the following items affected the forecast: (1) daily changes in the price of natural gas; (2) daily changes of power prices for the MISO market; (3) hedges put in place; (4) AES Indiana's coal inventory; and (5) gas commodity and delivery contracts. He stated based on the OUCC's analysis and review of commodity prices at the time of the audit, the OUCC is proposing a Fuel ÷ Sales of 43.631 mills per kWh to reflect the recent decrease in natural gas prices and increase in power prices.

In her rebuttal testimony, Ms. Coklow incorporated the OUCC's recommended Fuel ÷ Sales to determine the updated proposed FAC factor.

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

8. **Wind Power Purchase Agreements and Renewable Energy Credits.** Mr. Dickerson testified that purchases from the Lakefield Wind Park ("Lakefield") are included in AES Indiana's actual and projected fuel costs. He discussed the amount of power received from Lakefield during the Historical Period. He added that pursuant to the Order in Cause No. 45911, the margin associated with the Lakefield power purchase agreement ("PPA") is included in the Off-System Sales Margin Adjustment Rider.

Mr. Dickerson stated Lakefield is a Dispatchable Intermittent Resource 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 testified the level of curtailments at Lakefield was lower than the level of curtailments experienced during the Historical Period covered by the last FAC and higher than the Historical Period from one year ago.

OUCC Witness Eckert noted that Mr. Dickerson provided testimony to update the Commission on locational marginal prices at Lakefield. He stated AES Indiana offers Lakefield into the day-ahead market to mitigate the impact of negative locational marginal pricing in real-time.

In Cause No. 43740, the Commission approved AES Indiana's request to recover the purchased power costs incurred under the Lakefield PPA over its full 20-year term. 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.

9. Reconciliation and Resulting Fuel Cost Factor for Electric Service. According to AES Indiana's Exhibit No. 3, Attachment NHC-1R, Schedule 1R, AES Indiana's total estimated cost of fuel for the Forecast Period is $132,406,145, and its total estimated sales are 3,034,657 kWh. AES Indiana's estimated cost of fuel, after taking into consideration the proposed reconciliation component and the updated base cost of fuel approved in Cause No. 46258, is $0.005211 per kWh. App. Ex. 3, Attachment NHC-1R, Schedule 1R, Line 37.

Ms. Coklow discussed how the FAC factor was calculated. She explained that AES Indiana has included the remaining uncollected FAC 151 variance (50%) totaling $10,739,514 (from November 2025 through January 2026).

As shown on Schedule 1R of Attachment NHC-1R to Petitioner's Exhibit No. 3, after taking into consideration the reconciliation of AES Indiana's estimated and actual fuel costs, AES Indiana's estimated average cost of fuel for the Forecast Period is $0.043631 per kWh. As shown on Schedule 1R of Attachment NHC-1R to Petitioner's Exhibit No. 3, when the adjusted fuel cost charges are reduced by the base cost of fuel approved in Cause No. 46258, the result is the proposed fuel factor of $0.005211 per kWh for the Forecast Period's billing cycles. Ms. Coklow testified that in relation to the factor currently in effect, the proposed factor will result in an increase of $6.01 or 4.42% for a residential customer using 1,000 kWh per month. App. Ex. 3 at 3.

OUCC Witness Eckert recommended the Commission approve the proposed fuel cost factor as calculated by OUCC Witness Guerrettaz.

The record shows the parties agree on the proposed fuel factor of $0.005211 per kWh. Substantial record evidence supports AES Indiana's proposed fuel factor, including AES Indiana's collection of the remaining FAC 151 variance, and we find it should be approved. 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.

10. **Confidential Information.** On June 12, 2026, AES Indiana filed its Motion for Protection and Nondisclosure of Confidential and Proprietary Information with a supporting affidavit asserting 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. A Docket Entry was issued on July 1, 2026, in which the Presiding Administrative Law Judge determined 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. AES Indiana's proposed fuel factor set forth herein is approved.

2. Prior to implementing the approved rate, AES Indiana 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. AES Indiana 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 AES Indiana's FAC.

4. In its next FAC filing, AES Indiana shall update the Commission on its coal inventory and its projected coal burn and coal purchases.

5. The information filed in this Cause pursuant to AES Indiana'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.

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

<u>SWINGER, BAIN, JERRELLS, AND ZIEGNER CONCUR; DEIG ABSENT</u>:

APPROVED: AUG 26 2026

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: 2026.08.26 10:20:11
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Dana Kosco
Secretary of the Commission