ORIGINAL

Commissioner	Yes	No	Not Participating
Huston	√		
Freeman	√		
Krevda	√		
Ober			√
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 JUNE 2022 THROUGH AUGUST 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 AUTHORITY TO RECOVER COSTS OF THE FUEL HEDGING PLAN PURSUANT TO I.C. 8-1-2-42.	)	**CAUSE NO. 38703 FAC 135** **APPROVED: MAY 25 2022**

ORDER OF THE COMMISSION

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

On March 17, 2022, Indianapolis Power & Light Company d/b/a AES Indiana ("Applicant") 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 2022 through August 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) authority to recover costs of its fuel hedging plan.[1] On March 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 March 29, 2022.

On April 21, 2022, the Indiana Office of Utility Consumer Counselor ("OUCC") filed its report and direct testimony.

An Evidentiary Hearing was held at 1:00 p.m. on May 12, 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

[1] On March 24, 2022, Applicant filed a revision to Applicant's witness John Bigalbal's direct testimony.

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. Applicant 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 November 2021 through January 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 during a portion of this period, due to unique coal pricing and availability, Applicant's goal was to conserve and build coal inventory for winter reliability purposes. He said Applicant, in conjunction with the Independent Market Monitor ("IMM") developed an approved offering strategy that was aimed to increase inventory at the same time as maintaining station reliability. He explained that once a reliable inventory was achieved, Applicant returned to the normal commitment practices described in his testimony.

Mr. Jackson testified Petersburg Units 2, 3, and 4 were offered as economic for most of the period. He said during November and parts of December, the economic offer was at a higher market price allowed by the IMM to promote lower commitment and dispatch to allow coal inventory build for winter reliability. He stated during this same time period either Petersburg Unit 2 or Unit 4 were offered as must run to guarantee a unit was online for building heat and station reliability. He provided further detail on the Petersburg unit commitment decisions during the Historical Period and explained AES Indiana ran a short-term model to track the economic value of the Petersburg Units and the model runs provided a 30-day forward look. He sponsored a copy of the model runs in Applicant's Exhibit 2-C, Confidential Attachment DJ-3. He added that non-economic factors were also considered in unit commitment decisions, including reliability, price certainty, operational needs, and avoidance of startup costs. Additionally, he said unit commitment was impacted by the need to build coal inventory for winter reliability.

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 that although Applicant's inventory is currently within its target range, Applicant continues to actively manage its inventory levels. He noted Applicant's long-term coal contracts often contain some variability in the quantity of coal that Applicant can take under that particular contract. He said this allows Applicant to increase deliveries when coal burns go up and decrease deliveries when coal burns go down. He explained this contract variability is essential in managing the month-to-month variations in coal burns due to weather, market prices, and unit availability. However, 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 in the late summer and fall there was insufficient coal available in the market to purchase enough coal to meet burns and build inventory for winter reliability. To address this circumstance, Mr. Jackson testified Applicant took steps to preserve and build coal inventory. Beginning in November, Applicant temporarily dispatched the Petersburg units based on the relatively higher priced offers to purchase additional coal, working with the IMM, designed to

limit Petersburg coal units' commitment and dispatch, and reflect the costs to add inventory in the tight coal market. He said the objective was to build inventory to appropriate levels combined with additional purchases of coal in the fourth quarter of 2021 and first quarter of 2022 to maintain winter reliability. He testified the prudent decision was to take this action when there is a low risk of power scarcity to build coal inventory and ahead of the critical winter period.

Mr. Jackson explained by limiting economic commitment consistent with IMM approved values for coal inventory build and reflecting the market cost to obtain additional coal if it could be purchased, the corresponding dispatch of the Petersburg Units allowed Applicant to build coal inventory to appropriate levels. When it was believed coal inventory levels and forward purchases were appropriate to support projected winter coal burns, economic dispatch of the units reflected the weighted average cost of inventory coal prices.

Mr. Jackson testified Applicant did not use coal decrement pricing during the Historical Period. He further stated there is no decrement pricing in the Forecast Period. He added that AES Indiana has not been impacted by any coal supply interruptions for coal under contract, but coal markets are extremely tight and contracting for additional coal deliveries in the very near term is limited.

Mr. Jackson discussed the peak power transactions Applicant engaged in because of the Eagle Valley combined cycle gas turbine ("CCGT") outage, explained the process used to determine the appropriate volume of the power hedges, the facts and circumstances as they existed at the time the transaction was entered, the value of the Eagle Valley CCGT peak power hedge as compared to realized daily pricing, and the factors that impacted this value. Mr. Jackson said Applicant's Exhibit 1, Attachment NHC-1, Schedule 5, Line 20 separately identifies the realized gains or losses from the financial hedges. He said there were no transaction costs associated with these hedge transactions. He explained that for Cause Nos. 38703 FAC 133, 134, and 135 ("FAC 133–FAC 135"), the peak power purchased realized gains of $6,743,900. He stated these gains benefitted customers by offsetting the cost of purchased power during the corresponding FAC periods and reflect the risk reduction targeted by entering into the power hedges – locking in a fixed price for megawatt hour corresponding to the hedges. Mr. Jackson provided the settlement values of the hedges by month and FAC period and provided a workpaper containing calculation detail for the power hedge gains and losses.

Mr. Jackson testified Applicant has not completed any peak power hedges for the months of January or February 2022. He stated using analysis consistent with the process used to inform hedge decisions for the financial power hedges entered into for the months of June through October and December 2021, Applicant evaluated purchasing natural gas instead of peak power hedges. He said in prior evaluations, Applicant did not have economic energy length. He explained the circumstance was different in January and February, in that Applicant had economic energy length based on then-current natural gas and power prices. He said this available economic generation was at a lower cost than peak power prices if Applicant had elected to hedge with financial power. He testified that for this reason, Applicant elected to purchase natural gas instead of peak power to reduce risk for customers.

Mr. Jackson testified Applicant purchased 35,000 MMBtu/day of physical natural gas from the period of January 11 through January 31, 2022. He said the alternative, to remove an equal amount of risk from the portfolio, was to purchase 120 MW of peak power for the balance of the

January. He stated 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.

Mr. Jackson explained that when evaluated versus daily index price for the natural gas delivery point associated with the hedge, Applicant realized a savings of $287,438 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 this analysis can be seen on Workpaper DJ-4 and shows the decision to hedge natural gas instead of power created a $735,988 benefit for customers in January 2022. He explained Applicant will provide the same analysis for February 2022 in its next FAC.

Mr. Jackson also provided an update on the natural gas hedging transactions undertaken during the months of August 2021 through October 2021 for the December 2021 through February 2022 delivery periods. 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 into. 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 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 did meet their objectives. He said during the month of December 2021 and January 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 concluded that the Historical Period presented several extraordinary challenges that required Applicant to respond in unique ways. He stated, in his opinion, Applicant has 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.

Natalie Herr Coklow, Manager in Regulatory Accounting at AES U.S. Services, LLC, testified there was one purchased power financial hedge settled during the Historical Period. She stated the realized loss is reflected on Applicant's Exhibit 1, Attachment NHC-1, Schedule 5, Page 2, Line 20. Ms. Coklow explained that since the hedge is the result of the Eagle Valley outage, it has not been included in the variances requested in this filing and instead is included in the portion that is being deferred for the FAC 133 S1 subdocket. She said, as discussed previously in Cause Nos. 38703 FAC 133 and 134, there were power financial hedge realized gains during the reconciliation periods of June through October 2021 totaling $7,226,446. She stated the net of the realized gains and loss totaling $6,743,900 are not included in the variances requested in this filing and are included in the portion that is being deferred for the FAC 133 S1 subdocket. She added that Applicant did not incur any transactional fees associated with these hedge transactions. 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 2022 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 revised hedging program information to the Commission if a revision occurs.

Mr. Eckert also discussed Applicant's purchased power hedge 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 is taking reasonable steps to preserve and build coal inventory during tight market conditions, and that Applicant acted appropriately during the Historical Period to ensure sufficient coal inventory to maintain winter reliability ahead of the critical winter period. The record further shows Applicant's current coal inventory is within its target levels. As recommended by the OUCC, we direct Applicant to update the Commission on how it proposes to address its coal inventory and its 2022 projected coal burn and coal purchases in its next FAC.

Applicant also presented substantial evidence regarding its natural gas hedging program and the peak power hedges Applicant engaged in because of the Eagle Valley CCGT outage. The record shows the OUCC did not oppose Applicant's hedges and we find Applicant's purchased power hedges 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. Eagle Valley CCGT Outage. Mr. John Bigalbal, Chief Operating Officer, US Conventional Generation at AES US Services, LLC, provided an update on the forced outage at the Eagle Valley CCGT plant. He testified the Eagle Valley CCGT successfully started up both gas turbines and steam turbine. He said on March 15, 2022, Eagle Valley completed its MISO capacity test. He said the plant then operated with one gas turbine and the steam turbine on line from March 15 to March 18, 2022 to allow for Gas Turbine 2 and Heat Recovery Steam Generator 2 to cool while additional tuning changes were made and to test the gas turbine during a cold startup. He said these tuning changes were comprised of adjusting the fuel-to-air ratio for proper combustion and adjusting combustion and exhaust temperature to meet the Heat Recovery Steam Generator's warmup specification. Mr. Bigalbal explained the tuning changes were implemented and successfully tested on March 18, 2022. He added that the facility was released for full load dispatch on that same day. Finally, he stated Applicant is working to finalize the written Root Cause Analysis report.

Mr. Jackson testified that Eagle Valley CCGT was in forced outage for the entire historical period of May 2021 through January 2022. He said Applicant incurred purchased power costs over the benchmark of $4,869,729 during the FAC 133–FAC 135 historical period. He said the portion of purchased power above the benchmark that could be attributable to the Eagle Valley outage was $4,301,842. He explained that Applicant completed additional analysis outlining the impact of the Eagle Valley CCGT outage. He testified the analysis shows the total estimated impact to retail fuel cost was $35,168,380 for Eagle Valley CCGT to not be operational during the FAC 133–FAC 135 historical periods, net of the financial peak power hedge gains and losses of $6,743,900. The full analysis was provided in Applicant's Exhibit 2, Attachment DJ-5.

Mr. Eckert stated the Eagle Valley CCGT is no longer in a forced outage and was successfully restarted and achieved full load on March 14, 2022. He testified the OUCC recommends the Commission defer the investigation of the Eagle Valley CCGT forced outage and the related issues, energy and purchased power costs to the FAC 133 S1 subdocket to allow for a more detailed examination of costs and issues associated with the Eagle Valley CCGT outage. Further, he stated the OUCC recommends the Commission make the rates in this Cause interim and subject to refund, to reflect any cost recovery changes resulting from the decisions on the Eagle Valley CCGT outage and associated root cause analyses.

Applicant did not object to the OUCC's recommendation to defer the Eagle Valley CCGT forced outage and related issues to the FAC 133 S1 subdocket. We agree with the OUCC that, based on the facts in this circumstance, the review of the Eagle Valley CCGT forced outage discussed above is best accomplished outside the statutory time constraints of the FAC summary proceeding. Accordingly, the Commission finds the impact of the Eagle Valley CCGT extended outage on fuel costs will be examined in the FAC 133 S1 subdocket, and the recovery of such fuel costs herein is interim and subject to refund pending the outcome of the FAC 133 S1 subdocket.

5. <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 Order, and FAC 97 Order, and is approved. The Commission further finds Applicant's recovery of RSG Charges is consistent with the RSG Order and is approved.

6. <u>Purchased Power Costs Above Benchmark</u>. In its April 23, 2008, Order in Cause No. 43414 ("Purchased Power Order"), the Commission approved a Benchmark triggering mechanism to assess the reasonableness of purchased power costs. Mr. Jackson explained that each day, a Benchmark is established based upon a generic Gas Turbine ("GT"), using a generic GT heat rate of 12,500 btu/kWh and the day ahead natural gas prices for the New York Mercantile Exchange ("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 $4,869,729 of purchased power costs over the applicable Benchmarks during the FAC 133–FAC 135 periods. He said the non-outage related purchases over the Benchmark are estimated to be $567,887. Mr. Jackson said Applicant incurred a total of $2,487,937 of purchased power costs over the applicable Benchmarks during November 2021 through January 2022. 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 summarized 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. *See also* Applicant's Exhibit

2, Attachment DJ-2. 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 is proposing to include only the non-outage portion of the total FAC 133–FAC 135 purchases over the Benchmark of $567,887. Mr. Jackson said the forced outage related purchases over the Benchmark will be considered in the resolution of the pending FAC 133 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 $2,660 of purchased power over the Benchmark that is non-recoverable. Mr. Jackson testified these total purchased power costs during the Historical Period are reasonable, however, Applicant acknowledged this cost recovery remains subject to the FAC 133 S1 subdocket.

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 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 $2,487,937 in purchased power over the Benchmark be deferred to the FAC 133 S1 subdocket.

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 $2,487,937 in purchased power over the Benchmark will be determined in the FAC 133 S1 subdocket.

7. <u>Operating Expenses</u>. 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).

8. <u>Return Earned</u>. 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-4a, which calculate the (d)(3) test, show Applicant's actual return for the 12 months ending January 31, 2022.

She stated that Applicant's actual return is more than its authorized return for the 12 months ending January 31, 2022, and the sum of differentials for the relevant period also results in a positive amount. Accordingly, she stated a reduction in the fuel factor was calculated as specified by Ind. Code § 8-1-2-42.3(b).

Ms. Coklow described how the reduction amount of $282,364 was calculated and stated that this amount is included as a reduction to fuel costs recoverable in the current FAC period as shown on Attachment NHC-1, Schedule 1, Lines 32 and 33. Ms. Coklow explained that because Applicant anticipated that the earnings bank would be depleted during the fourth quarter of 2021, Applicant recorded the estimated liability that would result from the earnings test in this case for the Historical Period. She said Applicant excluded both the reduction to revenue and the associated tax impact due to these entries from net operating income for the 12 months ending January 31, 2022, earnings calculation presented on Attachment NHC-2 because it would be inappropriate to reduce the earnings in this current FAC period before the adjustment is reflected as a reduction to rates on Attachment NHC-1, Schedule 1. She said these adjustments to per books net operating income are shown on the 12-month net operating income statement worksheet that is included in the FAC audit packet. She explained both the reduction to revenue and the associated tax impact would be reflected in the earnings test in the next FAC.

Mr. Guerrettaz agreed Applicant had jurisdictional net operating income (for the 12 months ending January 31, 2022) greater 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. He reviewed the sum of differentials for the relevant period and the reduction calculated by Applicant and did not express any concerns with the calculation.

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, 2022, and properly reflected the return on its Qualified Pollution Control Property. Thus, as reflected in Attachment NHC-3 to Applicant's Exhibit 1, Applicant has an authorized return of $226,529,000 for purposes of this proceeding. Attachment NHC-2 to Applicant's Exhibit 1 calculates the (d)(3) test, which shows that Applicant's actual return for the 12 months ending January 31, 2022, was $227,361,000. Further, the sum of the differentials between the actual earned return and the authorized return for the relevant period as defined in Ind. Code § 8-1-2-42.3 is $275,608,218, as reflected on Attachment NHC-4 to Applicant's Exhibit 1. Thus, by the mechanics of the applicable statute, the Commission finds Applicant appropriately calculated and applied the reduction amount to its proposed fuel factor in light of the return earned by Applicant during the 12 months ending January 31, 2022.

9. <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 37.25% 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 drivers of the variance were the increase in natural gas prices, the Eagle Valley CCGT forced outage, and changes to coal commitment to build inventory for winter reliability leading to increased volumes of purchased power, particularly in November 2021. 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 and the factors that impacted Petersburg coal commitment and dispatch to build inventory for winter reliability.

Mr. Jackson testified that Applicant has changed the long-term planning model used to generate the long-term forecast. He said prior to Cause No. 38703 FAC 134 ("FAC 134"), the planning model was Ascend's PowerSimm model. He said beginning with FAC 134 and moving forward, the planning model is Anchor Power's EnCompass model. He stated either model produces an equally plausible economic dispatch of the units used in forecasts and said the primary reasons for switching models include quicker run times and more robust capacity forecasting capabilities with the EnCompass model. He testified Applicant introduced the model in the FAC 134 audit and will review the EnCompass model in more detail with the OUCC during the audit of this FAC.

Mr. Jackson stated natural gas prices have increased significantly, 47% higher, for the forecast period of June 2022 through August 2022, versus the same forecast period one year ago. He said the key drivers of this increase are uncertainty of domestic demand and robust export demand in the liquified natural gas market. He added that more recently, the war between Russia and Ukraine has supported natural gas and coal prices due to concern of global supply interruption or trade embargos on Russian commodities.

Mr. Guerrettaz stated the OUCC did a detailed review of Applicant's estimation model and noted the forecast had the following items affecting it: (1) the daily changes of the price of natural gas; (2) the 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 update of current natural gas and power prices, which would have increased the current Fuel ÷ Sales of 37.366 Mills per KWhs. He said therefore no changes were made. He noted the Fuel ÷ Sales cost used in this FAC uses generation from Eagle Valley, but the forecasted cost of natural gas used to run the facility is quite high due to market conditions.

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.

10. <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 lower than the level of curtailments experienced during the time period covered by FAC 134, and lower than the time period experienced one year ago in Cause No. 38703 FAC 131.

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.

11. <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 $139,890,655, and its total estimated sales are 3,743,783,000 kWh. Applicant's estimated cost of fuel, after taking into consideration the reduction for the earnings test and the proposed reconciliation component, is $0.046410 per kWh. Ms. Coklow testified that Applicant has completed its analysis of the estimated impact of the Eagle Valley outage on the variances from FAC 133–FAC 135 and is now able to model an estimate of the variances that were the result of issues independent of the Eagle Valley outage (commodity price and volume variances). 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 $68,281,936 and for mitigation purposes is proposing to spread the recovery over two FAC periods. 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 help to mitigate cash flow issues that can negatively impact Applicant.

Ms. Coklow testified that in January 2022 it was discovered that Duke Energy had provided incorrect meter readings to MISO at a substation where Applicant has tie-lines. She said this impacts the October 2021 variance from what was previously filed in FAC 134, resulting in a difference of $2,401,941. She said once MISO re-settles the market for these days, Applicant will receive refunds and MISO fuel-like charges will be lower in future months. She said the credits will be reflected in the FAC in the months they are received (anticipated to be January through March 2022) and are expected to total approximately $7.9 million.

Ms. Coklow testified Applicant is seeking authority to continue deferring as a regulatory asset the variances calculated during the reconciliation period of May 2021 through January 2022 attributable to the Eagle Valley CCGT outage (equaling an estimated $35,168,380) 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 and adjusted for Indiana Utility Receipts Tax, the result is the proposed mitigated fuel factor of $0.013673 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 $14.44 or 11.74% 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 $6.25 or 5.08% 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.

OUCC witness Guerrettaz testified the OUCC recommends the same FAC factor as Applicant that has been recalculated and confirmed. He noted that the Indiana Utility Receipts Tax ("URT") has been eliminated effective July 1, 2022 and, therefore, the factor with URT will be charged up to June 30, 2022 and the factor without URT will be billed in July and August 2022.

The Commission approves the proposed mitigated fuel factors of $0.013673 (June 2022 billing cycle) and $0.013472 (July and August 2022 billing cycles) on an interim basis, subject to reconciliation and true-up in a future FAC filing, or upon resolution of the Eagle Valley outage matters 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 Commission further grants Applicant accounting authority to continue deferring as a regulatory asset the variances calculated during the reconciliation period of May 2021 through January 2022 attributable to the Eagle Valley outage, subject to reconciliation and true-up as stated above.

12. <u>Confidential Information</u>. On March 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 March 29, 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. 11 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 January 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 2022 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; OBER ABSENT:

APPROVED: MAY 25 2022

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: 2022.05.25 10:20:41 -04'00' on behalf of

Dana Kosco
Secretary of the Commission