STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

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

APPLICANT'S SUBMISSION OF DIRECT TESTIMONY OF
DAVID JACKSON

Indianapolis Power & Light Company d/b/a AES Indiana ("AES Indiana", "IPL", "Company", or "Applicant"), by counsel, hereby submits the direct testimony and attachments of David Jackson.

Respectfully submitted,

Teresa Morton Nyhart (No. 14044-49)
Jeffrey M. Peabody (No. 28000-53)
Barnes & Thornburg LLP
11 South Meridian Street
Indianapolis, Indiana 46204
Nyhart Telephone: (317) 231-7716
Peabody Telephone: (317) 231-6465
Facsimile: (317) 231-7433
Nyhart Email: tnyhart@btlaw.com
Peabody Email: jpeabody@btlaw.com

ATTORNEYS FOR APPLICANT
INDIANAPOLIS POWER & LIGHT COMPANY
D/B/A AES INDIANA

CERTIFICATE OF SERVICE

The undersigned hereby certifies that a copy of the foregoing was served this 17th day of June, 2022, by email transmission, hand delivery or United States Mail, first class, postage prepaid to:

Lorraine Hitz
Office of Utility Consumer Counselor
115 W. Washington Street, Suite 1500 South
Indianapolis, Indiana 46204
infomgt@oucc.in.gov
lhitz@oucc.in.gov

Gregory T. Guerrettaz
Financial Solutions Group, Inc.
2680 East Main Street, Suite 223
Plainfield, Indiana 46168
greg@fsgcorp.com
fsg@fsgcorp.com

A Courtesy Copy to:
Anne E. Becker
Lewis & Kappes
One American Square, Suite 2500
Indianapolis, Indiana 46282
abecker@lewis-kappes.com

and a courtesy copy to:
ATyler@lewis-kappes.com
ETennant@Lewis-kappes.com

Jeffrey M. Peabody

Teresa Morton Nyhart (No. 14044-49)
Jeffrey M. Peabody (No. 28000-53)
Barnes & Thornburg LLP
11 South Meridian Street
Indianapolis, Indiana 46204
Nyhart Telephone: (317) 231-7716
Peabody Telephone: (317) 231-6465
Facsimile: (317) 231-7433
Nyhart Email: tnyhart@btlaw.com
Peabody Email: jpeabody@btlaw.com

ATTORNEYS FOR APPLICANT
INDIANAPOLIS POWER & LIGHT COMPANY
D/B/A AES INDIANA
DMS 22936384v1

VERIFIED DIRECT TESTIMONY OF DAVID JACKSON
DIRECTOR, COMMERCIAL OPERATIONS

Q1. Please state your name, employer, and business address.

A1. My name is David Jackson. I am employed by AES US Services, LLC ("the Service Company"), which is the service company that serves Indianapolis Power & Light Company d/b/a AES Indiana ("AES Indiana", "IPL", "Applicant", or the "Company"). The Service Company is located at One Monument Circle, Indianapolis, Indiana 46204.

Q2. What is your position with the Service Company?

A2. I am the Director, Commercial Operations.

Q3. What are your current responsibilities as the Director, Commercial Operations?

A3. As Director, Commercial Operations, I am responsible for managing AES Indiana's participation in the Midcontinent Independent System Operator, Inc. ("MISO") energy market and oversight of AES Indiana's strategy and execution for demand bids and generation offers. I am also responsible for the management of AES Indiana's wind power purchase agreements ("PPAs") and procurement of natural gas and coal.

Q4. Please briefly describe your educational and business experience.

A4. I received a Bachelor of Science Degree in Agricultural Industries from the University of Illinois at Champaign-Urbana. I have been employed by AES since 2015, assuming my current role in May of 2018. Previously, I held the position of Director, Commercial Operations AES Ohio Generation. Prior to AES, I worked at Duke Energy, Cincinnati, Ohio (previously Cinergy Services, Inc.) between 2002 to 2015, as the Director, Coal Trading.

Q5. Have you previously testified before the Indiana Utility Regulatory Commission ("Commission")?

A5. Yes. I have submitted testimony on behalf of AES Indiana in previous FAC proceedings.

Q6. What is the purpose of your testimony in this proceeding?

A6. My testimony supports:

- AES Indiana's request to recover through the FAC proceeding certain costs incurred by AES Indiana as a result of taking transmission service under the MISO Open Access Transmission and Energy Markets Tariff ("TEMT") to serve its retail electric customers, and participating in the MISO Day-Ahead and Real-Time Energy and Financial Transmission Rights ("FTR") Markets and MISO Energy and Operating Reserves Market ("MISO EOR").
- AES Indiana's unit commitment process and decisions.
- AES Indiana's inclusion of its wind and natural gas purchases in this FAC, coal purchases, and the reasonableness of AES Indiana's fuel costs.
- Update on AES Indiana's 2022 projected coal burn and coal purchases.
- The Eagle Valley CCGT forced outage and how AES Indiana has acted to mitigate the price risk of the outage by completing hedges.
- Settlement costs associated with winter natural gas hedges.
- In FAC 127, I testified that AES Indiana is implementing a short-term model, which will better track Petersburg Generation Station ("Petersburg") Unit economics. My

testimony updates the Commission on the short-term model, which has been in use since the end of May 2020.

- Finally, the Company agreed to provide information regarding the evaluation of the firmness needs for gas supply at Harding Street. Confidential Attachment DJ-11 provides this evaluation.

Q7. Are you sponsoring any attachments?

A7. Yes. I am sponsoring the following attachments:

- Attachment DJ-1 – Calculation of daily benchmarks.
- Attachment DJ-2 – Summary of purchased power volumes, costs, the total of hourly purchased power costs above the applicable Purchased Power Daily Benchmarks, and the reasons for purchases at-risk after consideration of MISO economic dispatch.
- Attachment DJ-3 – an adjusted version of Attachment DJ-2 to determine recoverable purchased power over the benchmark after removing Eagle Valley MW from Units with Full Forced Outage.
- Confidential Attachment DJ-4 – Commitment summary and weekly model runs used in Petersburg commitment decisions February 2022 through April 2022.
- Confidential Attachment DJ-5 – 2022 Petersburg Coal Position and provides a monthly view of 2022 purchases, burns, and inventory.
- Attachment DJ-6 – Estimated Impact of The Eagle Valley CCGT Forced Outage for FAC133 through FAC136, which compares actual historical fuel costs to estimated actual fuel costs had Eagle Valley CCGT been operational. Eagle Valley CCGT returned to service on March 18, 2022, during the FAC 136 reconciliation period.

- Attachment DJ-7 – Evaluation of settled natural gas hedge versus considered peak power hedge for February 2022.
- Attachment DJ-8 – which provides detailed calculations of the costs associated with the winter natural gas hedges impacting this historical FAC period.
- Attachment DJ-9 – provides evaluation of the hedges' economic settlement in April.
- Confidential Attachment DJ-10 – shows completed hedging transactions and remaining balances to be completed for the hedging policy approved in FAC 133.
- Confidential Attachment DJ-11 – Firm Transportation Strategy for Harding Street.

Q8. Were these attachments prepared or assembled by you or under your direction and supervision?

A8. Yes.

Q9. Are you submitting any workpapers?

A9. Yes. I am submitting Jackson Confidential Workpaper 1, which supports Table DJ-4, and the Excel workbooks which support my attachments. This workpaper was prepared or assembled by me or under my direction and supervision.

MISO

Q10. Are you generally familiar with the operations of MISO?

A10. Yes, I am.

Q11. Have you reviewed the Commission's June 1, 2005 Order in Cause No. 42685 ("June 1, 2005 Order")?

A11. Yes.

Q12. Have you reviewed the Commission's June 30, 2009 Order in Cause No. 43426 ("Phase II Order")?

A12. Yes.

Q13. Is AES Indiana's calculation of costs for September 2022 through November 2022 consistent with your understanding of the Commission's June 1, 2005 Order and Phase II Order?

A13. Yes.

Q14. Are you generally familiar with the costs incurred by AES Indiana as a result of taking transmission service under MISO's TEMT to serve its Indiana retail electric customers?

A14. Yes.

Q15. Can you briefly explain the benefits to AES Indiana's customers of AES Indiana's participation in the MISO EOR?

A15. The MISO EOR gives all participants open access to the transmission system and all available resources are centrally dispatched using simultaneous co-optimization. MISO provides a transparent and liquid energy market across its entire footprint. Furthermore, on-going coordination between MISO and adjacent ISO systems increases grid reliability and makes it possible to regionally coordinate transmission expansion. While benefiting from improved grid reliability, the greater benefit for AES Indiana and its customers is the transparent and liquid energy market that brings about an even playing field for all utilities. This allows AES Indiana to make more economic purchases from the open market with the benefits flowing directly to its customers. The EOR provides the same level playing field for ancillary services (regulation and contingency reserves) while also more effectively and economically allocating resources to provide those reserves. In addition, the EOR provides an opportunity to reduce the overall amount of reserves being held by market participants thereby further reducing the cost of providing those reserves to customers.

Q16. Briefly describe the MISO costs and revenues that AES Indiana is seeking to recover in this FAC proceeding.

A16. AES Indiana is requesting recovery of projected fuel-related MISO costs for the period of September 2022 through November 2022. These projected costs include the estimated level of the net effect of revenues and costs associated with delta Locational Marginal Pricing ("LMP"), Day-Ahead and Reliability Assessment Commitment ("RAC") unit commitment, FTRs, Real-Time Marginal Loss Surplus, and Ancillary Services. In addition, AES Indiana's calculation of the unmitigated fuel factor reflects a reconciliation of these fuel-related MISO costs and revenues for the historical period of February 2022 through April 2022. Attachment NHC-1, Schedule 6 contains a summary of the determination of actual MISO Components of Fuel Costs, exclusive of purchased power costs for this period.

Q17. How did AES Indiana forecast costs for the September 2022 through November 2022 period?

A17. The longer-term forecasts presented in this proceeding were generated in a planning model that looks at the economic dispatch of the units on the day the model is run to allow for preparation of the schedules used in this filing. It is reasonable to use this forecast for purposes of this proceeding. As discussed below, commitment decisions in the actual period will be driven by pricing, protecting customers from price risk, operational conditions, and reliability. As stated below, the Eagle Valley CCGT is included in the forecast.

Q18. Has AES Indiana compared natural gas prices for the forecast period September through November 2022 to the forecast period for September through November 2021?

A18. Yes. As evident in the table below, natural gas prices have increased significantly, 288% higher, for the forecast period of September 2022 through November 2022, versus the same forecast period one year ago. This significant increase in natural gas prices for the forecast period is the primary driver for the fuel factor proposed in this proceeding. The key drivers of the natural gas price increase are uncertainty of domestic supply and increased demand. Natural gas production has been slow to respond to higher prices and demand from electric generation has been high. Export demand in the LNG market remains robust. The war between Russia and Ukraine continues to support higher natural gas and coal prices due to concern of global supply interruption and trade embargos on Russian commodities. Additionally, higher natural gas pricing reflects inventory builds to prepare for the winter 2022-2023, to guarantee necessary supply to support heating demand and projected power burns. Coal markets remain tight and the assumption is that natural gas will see increased burns from fuel switching due to availability concerns of coal on a national level. Changes in the EPA Seasonal NOx program have also encouraged fuel switching from coal to natural gas.

Table DJ-1 Comparison of Natural Gas Prices

Natural Gas $/MMBtu	September	October	November	3 Month Average
Forecast FAC 132	2.98	2.99	3.07	3.01
Forecast FAC 136	8.65	8.64	8.69	8.66
Price Variance	5.67	5.65	5.62	5.65
% Change	290%	289%	283%	288%

Q19. Are there other factors impacting the forecast period?

A19. Yes. AES Indiana shifted a planned outage on Petersburg Unit 4 from the fall period of 2022 to the spring period of 2023. The move creates a forecast benefit of $20 million in energy margin. This benefits customers through a $6 million reduction to rates during the forecast period, with the balance reflected in increasing Off System Sales ("OSS") margins. The model data in the forecast period shows that the high market heat rates increase the generation volumes of the Company's assets. All power modelled to serve customer load is coming from AES Indiana generation assets and Purchase Power Agreements for the months of October and November; none of the power to serve load in those months is purchased from MISO. Because of the amount of generation forecast to be online, the fuel mix of power to serve load is elevating the cost of power due to the higher cost of natural gas units. The offsetting benefit is the expectation of higher OSS margins, which flow 100% back to customers.

Q20. In its FAC 97 Order, the Commission authorized AES Indiana to include charges for Demand Response Resource Uplift Amounts for purposes of recovery in the FAC proceedings. Has AES Indiana included these charges in this FAC proceeding?

A20. Yes. Consistent with the FAC 97 Order, AES Indiana has included the charges for Demand Response Resource Uplift Amounts in its cost of fuel in this proceeding.

Q21. In its FAC 85 Order, the Commission authorized AES Indiana to include credits or charges for Contingency Reserve Deployment Failure Charge Uplift Amounts for purposes of recovery in the FAC proceedings. Has AES Indiana included these credits or charges in this FAC proceeding?

A21. Yes. Consistent with the 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.

Q22. Please discuss AES Indiana's experience with MISO's Ancillary Services Market ("ASM").

A22. MISO launched its ASM on January 6, 2009, and to my knowledge the ASM has generally functioned without major issue. AES Indiana's generators follow real time signals as directed by MISO. As discussed in FAC 134, MISO implemented a new ancillary services product called Short Term Reserve ("STR"). The new product and settlements treatment were discussed in FAC 134. MISO Day Ahead and Real Time market clearing prices for Regulation, Spinning, Supplemental Reserves and Short Term Reserve appear to be at reasonable levels consistent with market conditions. For the period of February 2022 through April 2022, the average ASM prices per megawatt hour were as follows:

Table DJ-2 Average ASM Prices per Megawatt-Hour

Month	Regulation	Spinning	Supplemental	STR
February 2022	$0.0409	$0.0331	$0.0028	$0.0213
March 2022	$0.0452	$0.0467	$0.0033	$0.0170
April 2022	$0.0733	$0.0757	$0.0070	$0.0486

Q23. Is AES Indiana requesting recovery of Revenue Sufficiency Guarantee ("RSG") Payments in this FAC proceeding?

A23. Yes.

Q24. Have you reviewed the Commission's June 3, 2009 Order in Cause No. 43664 (the "RSG Order")?

A24. Yes.

Q25. Is AES Indiana's request for recovery of RSG Payments consistent with your understanding of the Commission's RSG Order?

A25. Yes.

Q26. Are you familiar with the term "Contestable RT RSG Charges"?

A26. Yes. In its RSG Order, the Commission approved the following calculation method ("RSG Daily Benchmarks") to be used to determine the RSG Benchmark:

> Each day a "Benchmark" shall be established based upon a generic Gas Turbine ("GT"), using a generic GT heat rate of 12,500 btu/kwh using the day-ahead natural gas prices for the NYMEX Henry Hub, plus a $0.60/mmbtu gas transport charge for a generic gas-fired GT.

Any Revenue Sufficiency Guarantee First Pass Distribution amounts in excess of the RSG Daily Benchmarks are termed "Contestable RT RSG Charges" and are currently recovered through the RTO rate adjustment mechanism.

Q27. What are the RSG Daily Benchmarks for the period of February 2022 through April 2022?

A27. The applicable RSG Daily Benchmarks per MWh for RSG during the historical period are shown on Attachment DJ-1. The RSG Daily Benchmark calculations have been done in conformity with the RSG Order.

Q28. How does AES Indiana recover the cost of power purchased in the MISO markets?

A28. AES Indiana recovers power costs purchased through the MISO energy market, up to a Daily Benchmark, through the FAC. In Cause No. 43414, the Commission approved a "benchmark" triggering mechanism to assess the reasonableness of purchased power costs ("Purchased Power Order"). Each day, a Benchmark is established based upon a generic Gas Turbine ("GT"), using a generic GT heat rate of 12,500 btu/kWh, using the day ahead natural gas prices for the NYMEX Henry Hub, plus $0.60/mmbtu gas transport charge for a generic gas-fired GT. The Benchmark methodology was approved in Cause No. 43414 on April 23, 2008 ("Purchased Power Daily Benchmark(s)"). AES Indiana continues to follow the guidelines and procedures established in the Purchased Power Order. Purchases made in the course of MISO's economic dispatch regime to meet jurisdictional retail load are a cost of fuel and are fully recoverable in the utility's FAC up to the actual cost or the Purchased Power Daily Benchmark, whichever is lower.

Q29. What are the Purchased Power Daily Benchmarks for February 2022 through April 2022?

A29. The applicable Purchased Power Daily Benchmarks during this accounting period are shown in Attachment DJ-1. The approved methodology for determining the Purchased Power Daily Benchmarks and the RSG Daily Benchmarks is identical.

Q30. Is AES Indiana seeking to recover any purchased power costs that are in excess of the Daily Benchmarks calculated pursuant to the Purchased Power Order?

A30. Yes. For the FAC 136 historical period, AES Indiana incurred a total of $498,872 of purchased power costs over the applicable Purchased Power Daily Benchmarks during February 2022 through April 2022. AES Indiana makes power purchases when economical or due to unit unavailability. Consistent with the Purchased Power Order, AES Indiana has an opportunity to request recovery of and justify the reasonableness of purchased power costs above the applicable Purchased Power Daily Benchmark. Attachment DJ-2 was prepared to aid the Commission in its review of AES Indiana's request. Attachment DJ-2 summarizes the purchased power volumes, costs, the total of hourly purchased power costs above the applicable Purchased Power Daily Benchmarks and the reasons for the purchases at-risk after consideration of MISO economic dispatch for FAC 136. Utilizing the methodology approved in the Purchased Power Order, $0 of the purchased power would be non-recoverable during this accounting period. The Company is proposing to include in the factor the non-outage-related portion of the purchases over the benchmark of $205,516. The outage-related purchases over the benchmark will be deferred and considered in the resolution of the pending subdocket in FAC 133.

Additionally, as shown in Attachment DJ-3 for the FAC 136 historical period, removing the seasonal capacity MW of Eagle Valley from the MW for Units with Full Forced Outage results in $972 of purchased power over the benchmark that is non-recoverable as compared to $0 in Attachment DJ-2.

Q31. What were the primary drivers of the purchased power costs above the benchmark during the historical FAC period?

A31. Almost half of the purchased power over benchmark occurred over two days. On February 20, 2022, Harding Street 7 missed its start because of water chemistry issues in the boiler during startup. The cost of purchased power over benchmark was $95,845. On March 13, 2022, customer load came in much higher in the real time due to weather changes. The cost of purchased power over benchmark for the day was $120,062.

Q32. Do you believe the total purchased power costs incurred in February 2022 through April 2022 are reasonable?

A32. Yes.

FUEL PURCHASES

Q33. Are you familiar with AES Indiana's purchases of fuel for use in its generating stations?

A33. Yes, I have reviewed the coal and natural gas contracts. I am copied on communications for daily activity in the natural gas purchases for real time and day ahead needs.

Q34. Are purchases for natural gas included in this FAC?

A34. Yes. Natural gas purchases to supply the generating units at Georgetown, Eagle Valley, and Harding Street are included in this filing. The forecasted natural gas generation is included on Attachment NHC-1, Schedule 1, Line 5, and the forecasted cost of natural gas is included on Attachment NHC-1, Schedule 1, Line 19. The actual natural gas generation is included on Attachment NHC-1, Schedule 5, Line 5, and the actual cost of natural gas is included on Attachment NHC-1, Schedule 5, Line 19. The cost of gas generation contains the delivered cost of natural gas including firm transportation.

Q35. How does AES Indiana make fuel oil purchases?

A35. Harding Street and Petersburg manage their own fuel oil purchases based on inventory set-points and regional market index pricing negotiated in a competitively bid contract.

Q36. How does AES Indiana purchase its coal supply?

A36. AES Indiana normally purchases all of its coal from the Illinois Basin, primarily from Indiana producers. We currently have contracts with three coal producers and receive coal from up to four different mines.

Q37. With what coal companies does AES Indiana presently have contracts?

A37. Peabody Energy Corporation, Sunrise Coal, LLC, Gibson County Coal Company.

Q38. Does AES Indiana have any ownership interest in any of these companies?

A38. No.

Q39. Why does AES Indiana engage in spot purchases of coal?

A39. We use spot purchases of coal in three ways: (l) to provide the differential requirement between our long-term contracts and our projected burn for the year; (2) to test the quality and reliability of a producer to see if we may want to utilize the company as a long-term supplier; and (3) when our projected inventory levels allow, to take advantage of occasional low price market opportunities.

Q40. What procedure does AES Indiana follow in negotiating long-term coal contracts?

A40. Fuel Supply has the responsibility of obtaining the necessary coal supplies and uses as a resource the long-range load and energy forecasts provided by our Resource Planning Group. AES Indiana constantly monitors coal producers as to the availability of reserves, capacity to produce, and current mining costs. Based on the above data, we solicit the market through a competitive bidding process and negotiate the price, terms and conditions on any contract extension or new contracts. AES Indiana typically uses long-term contracts of staggered lengths in order to limit our exposure to the market in any given year.

Q41. Why does AES Indiana normally purchase substantially all of its coal from Indiana providers?

A41. Although Fuel Supply actively solicits bids from Indiana and non-Indiana coal producers, potential coal contracts are evaluated on the total delivered cost to the plant. In the last few years, some out-of-state bidders have offered very competitive coal prices at the mine, but because of transportation costs, these bids were not our lowest cost option on a delivered basis. In addition, buying from local suppliers increases the reliability of supply by decreasing the risk of disruptions and lengthy delays in the transportation of coal to the plants. AES Indiana's present boilers are all designed for Indiana coal.

Q42. You stress that a reliable supply of fuel is necessary. Will you elaborate on the need for a reliable coal supply and the use of long-term contracts to meet that end?

A42. As a public utility, AES Indiana has an obligation to make every reasonable effort to acquire fuel and generate or purchase power, or both, so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible. We continue using long-term coal contracts as our primary means of maintaining a reliable supply. Long-term contracts provide coal producers with certainty and the ability to most economically allocate their resources, thereby reducing their overall production costs and allowing producers to sell at a lower cost. Even though most long-term contracts contain some volumetric flexibility, this flexibility may not be enough to absorb the volatility seen in recent markets. While AES Indiana cannot primarily rely on spot purchases for a reliable supply of coal, the spot market can be a useful tool for managing exposure to volatile markets. However, over-reliance on the spot market presents a number of risks. While spot contracts vary over time, they do not create the market efficiencies that translate into the lowest price over an extended period of time. Some spot market suppliers may not have enough capital to protect themselves in market downturns and they could go out of business, which could leave AES Indiana without coal. In addition, some small producers do not have adequate quality control in their mining operations, and it may be necessary to reject them as suppliers based on their inability to supply uniform coal quality in terms of Btu, moisture, ash, and sulfur content. Finally, even well-financed producers of high-quality coal may have their entire production run committed to established contracts and have no extra coal to offer to the spot market.

Q43. What does AES Indiana do to verify the reasonableness of its coal costs?

A43. AES Indiana uses a formal competitive bidding process to award its coal contracts. 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 AES Indiana's next best alternative. In addition, in long-term contracts that contain specific cost elements that can be passed through to AES Indiana (for example, costs associated with meeting new governmental regulations), we reserve the right to have those costs audited by an independent expert to aid in the proper administration of the contracts. This is done to protect our customers from any unnecessary or unreasonable fuel expense. Transportation costs are reviewed and monthly delivery schedules are designed to minimize the total transportation cost.

WIND PURCHASES

Q44. Are any purchases from the Hoosier Wind Park and/or Lakefield Wind Park included in this FAC, either in projected or actual fuel costs?

A44. Yes, wind purchases are included in AES Indiana's projected and actual fuel costs. The wind park operators provide AES Indiana with monthly wind production projections. AES Indiana forecasts wind purchase costs using the monthly production projections, contract rates, and a factor to account for the impact of expected levels of MISO real-time curtailments. AES Indiana forecasts wind purchase volumes by reducing the monthly production projections by the expected level of MISO real-time curtailments, which is largely based on historical curtailments at each park for the forecast period. Pursuant to the approval received in Cause No. 43485, AES Indiana began receiving power from Hoosier Wind Park on November 1, 2009. For the months of February 2022, March 2022, and April 2022, AES Indiana received 30,882 MWhs, 28,843 MWhs, and 24,879 MWhs, respectively. Pursuant to the approval received in Cause No. 43740, AES Indiana began receiving power from Lakefield Wind Park on October 4, 2011. For the months of February 2022, March 2022, and April 2022, AES Indiana received 38,997 MWhs, 28,837 MWhs, and 24,489 MWhs, respectively. Pursuant to Cause No. 43740, AES Indiana is reflecting credits to jurisdictional fuel costs for the off-system sales profits made possible because of the energy received from the Lakefield Wind Park PPA.

Q45. Where are these wind purchases shown in AES Indiana's schedules in this proceeding?

A45. Projected wind purchases are included in Purchases through MISO on Attachment NHC-1, Schedule 1, Line 6 and Line 20. Actual purchases are included on Attachment NHC-1, Schedule 5, Line 6 and Line 21.

Q46. Please provide an update regarding the Locational Marginal Prices ("LMPs") at the Lakefield Wind Park and the Hoosier Wind Park.

A46. The Lakefield Wind Park and the Hoosier Wind Park are Dispatchable Intermittent Resources ("DIRs") in the MISO market. A DIR is sent dispatch instructions from MISO by an electronic signal every five minutes, similar to the operation of the other generating units. The Lakefield Wind Park and Hoosier Wind Park can ramp quickly, largely avoiding negative LMPs. Curtailed power at the Lakefield Wind Park is billable when certain criteria are met. Curtailments at Hoosier Wind Park fall into two categories: Transmission Curtailments and Economic Curtailments. AES Indiana must pay for (i) Transmission Curtailments up to an identified annual quantity threshold and (ii) all Economic Curtailments. The level of curtailment at the Lakefield Wind Park, measured as a percentage of full theoretical production at the Lakefield Wind Park, were higher than the level of curtailments experienced during the time period covered by FAC 135, and lower than the time period experienced one year ago (FAC 132). There were no billable curtailments at the Hoosier Wind Park for this FAC period. AES Indiana also offers the Lakefield Wind Park and the Hoosier Wind Park into the day-ahead market to mitigate the impact of negative LMPs in real-time.

PETERSBURG UNIT COMMITMENT

Q47. Please provide an overview of the AES Indiana's unit commitment process.

A47. AES Indiana's units can be offered into the MISO market under one of five designations: "outage", "economic", "emergency", "not participating" or "must run". The outage designation indicates that the unit is under repair, either scheduled or forced. The economic designation offers the unit to the market at a set price and MISO decides whether that unit runs or not. As stated in the MISO Tariff Module C, an emergency commitment status indicates the unit is only available under an emergency condition for the hour. A not participating status indicates the Market Participant will not operate a unit that is otherwise available. The must run designation indicates that the unit should run through the period regardless of price signals, although the output level will be determined by market price. Generally, 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 that would be necessary to re-start the unit is also considered. Additionally, AES Indiana considers reliability, price certainty from running generation, and opportunities from participating in both Day Ahead and Real Time energy markets. During seasonal periods (summer and winter) with historical high market price and potential high load, AES Indiana will maintain a generation mix that includes coal, natural gas, and renewables. AES Indiana raises the minimum operating level when required to maintain reliability or for other operational reasons. Under normal conditions, AES Indiana offers the Petersburg units to be dispatched by MISO between their minimum economic operation level and maximum economic operation level. In other words, the decision to offer a unit considers a wide range of factors. Some 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, some considerations revolve around system reliability. System reliability issues are particularly important during the winter and summer peaks. A system is more reliable when supported by a diverse fuel mix. Units that are 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.

Q48. Please explain what you mean by *predicted* economic performance of the unit and "realized day ahead pricing".

A48. *Predicted* economic performance is based on expectations of the forward pricing. AES Indiana uses the Intercontinental Exchange ("ICE") financial trading platform and power broker end of day markets for forward pricing. *Realized* day ahead pricing is the price awarded by MISO when the unit is cleared in the day ahead market. Forward pricing is based on market expectations of factors that impact those prices. Forward prices are not always what are realized and, as mentioned previously, there are other critical factors considered in unit commitment including price certainty and reliability.

In the summer and winter months, forward power markets typically have price uncertainty due to the potential for abrupt changes in weather. The Company's unit commitment decisions are based on forward prices, as well as the other factors previously described. While the Company commits its generating units utilizing the best known information at the time, the future can unfold in different ways. The Company monitors the realized pricing to facilitate understanding of the market going forward. However, at the point in time a unit commitment decision is made, the Company does so without the benefit of hindsight. Even where the realized prices come in lower than expectation, the Company cannot know, with confidence, how the market will continue to move. Also, it is difficult to make the decision to de-commit a coal unit in a time period that presents a great deal of price risk for our customers. Operating baseload coal units assures relatively low cost of power during a historically volatile summer and winter time period for AES Indiana's customers and reduces price risk for the benefit of customers.

The commitment of baseload units may result in certain periods where individual units operate below their respective cost. However, as previously discussed, committing baseload units during certain periods provides a reasonable hedge for customers. By creating a ceiling for power prices that will ultimately be flowed through rates, the hedge protects the customer during periods of higher risk and associated higher costs, including costs that stem from scarcity events that can occur during the summer and winter period.

Q49. What is your understanding of how prudence is assessed?

A49. My understanding is that the focus in a prudence inquiry is not whether a given decision or action produced a favorable or unfavorable result, but rather, whether the process leading to the decision or action was a logical one, and whether the utility company used good judgement, applied appropriate standards, and reasonably relied on information and planning techniques known at the time.

Q50. Did the Company act prudently with respect to the commitment and operation of Petersburg during February 2022 through April 2022?

A50. Yes. The operation of Petersburg Generation Station during this period followed the prudency practices described above. For commitment decisions during this period, we evaluated the visible power market prices versus the cost of the Petersburg Units.

Decisions were based on market pricing that the Company witnessed at the time commitment decisions were made. The Company also considered non-economic factors as discussed earlier in my testimony.

Q51. Is it reasonable to rely solely on pricing to decide whether and how to commit AES Indiana's generating units?

A51. No. Simply looking back on energy prices for a given period, and comparing it to the cost of generation, does not capture the value of the non-monetary considerations weighed during the commitment decision. Oftentimes, running at a short-term loss benefits customers in a number of ways. For example, certain start-up costs are avoided, long-term maintenance costs associated with cycling units are minimized and customer prices are stabilized due to the fact that a unit is on-line and ready to respond to market disruptions. It is also important to again consider the value of the Petersburg Generation Station as a hedge against high prices for customers in traditionally volatile-priced periods. Price forecasts are not perfect and can deviate significantly from actual market conditions for many reasons. Factors such as the time involved in bringing base load units back online, the potential to have difficulty bringing units back after long outage periods, and the potential for other MISO resources to have operational issues, can create significant price risk for AES Indiana's customers.

Q52. Was total fuel cost divided by sales (F/S) on <u>Attachment NHC-1</u>, Schedule 5, Page 4 of 4, Line 32, higher than forecast during February 2022 through April 2022?

A52. Yes. The actual fuel costs were higher than forecast, resulting in a weighted average deviation of -17.75%. The February 2022, March 2022, and April 2022 deviations of actual to forecast F/S were -21.24%, -6.94%, and -23.87%, respectively. The largest driver of the variance was the increase in natural gas prices. The forecast fuel cost for the months of February 2022, March 2022, and April 2022 used a Henry Hub price of $4.40/MMBtu, $3.59/MMBtu, and $3.50/MMBtu, respectively. Realized values during the historical period were $4.67/MMBtu in February 2022, $4.86/MMBtu in March 2022, and $6.47/MMBtu in April 2022. The increase in natural gas price in the historical FAC period elevated market prices of purchased power. Although natural gas prices realized slightly higher than forecast in February 2022, winter natural gas hedges transacted by AES Indiana were at higher values than gas prices used in the forecast period. The forced outage of the Eagle Valley CCGT impacted February 2022, as the unit was modeled as available, by increasing the volume of purchased power covered in the marketplace versus baseload values from expected generation. The Eagle Valley CCGT was modeled as unavailable for the months of March and April 2022, so its March 18 return to service provided the offset of lower cost baseload generation against rising fuel prices. The February 2022, March 2022, and April 2022 Indianapolis temperature variance from normal was -1.7 degrees, +3.1 degrees, and -2.2 degrees, respectively.

Q53. Can you provide more detail regarding the natural gas price during the February 2022 through April 2022 period?

A53. Yes. Natural gas prices increased dramatically during the historical FAC period. The key drivers of this increase were natural gas production remained static even with the incentives of capturing higher priced sales in the rising market, demand from the electric generation has remained high, LNG exports are at maximum levels for the foreseeable future, coal remains tight and combined with rising emissions prices make natural gas fuel switching from coal likely. The breakout of war between Russia and Ukraine created a great deal of uncertainty in the global energy markets and it sent fuel prices (coal and natural gas) markedly higher as a result. In the February period, forecast Henry Hub natural gas prices were near $4.40/MMBtu and prices realized below those levels but were offset by higher priced natural gas hedges discussed in Q&A 79. Prices realized lower during December and January due to mild weather and the lack of scarcity pricing events.

Q54. Please summarize the status of the Petersburg Units during the February 2022 through April 2022 historical time period.

A54. During the historical FAC period, Petersburg Units 2, 3, and 4 were offered as economic for the majority of the period.

Q55. Please summarize the commitment status of each of the Petersburg units during the February 2022 through April 2022 time period.

A55. The table below shows the percentage of time the Petersburg Station units spent in either "must run", "economic", "emergency", and "outage" in the MISO day ahead offers.

<u>Table DJ-3 – Petersburg Commitment Status</u>

Commitment Status During FAC 136 Historical Period			
	Pete 2	**Pete 3**	**Pete 4**
Must Run	4%	0%	0%
Economic	63%	83%	72%
Emergency	0%	0%	0%
Outage	33%	17%	28%

Petersburg Units 2, 3, and 4 were typically committed as economic to MISO during the historical FAC period. Commitment decisions are discussed in more detail in Q/A 58 and <u>Confidential Attachment DJ-4</u>.

Q56. Did you document the forward pricing reflected in the unit commitment decisions for the months of February 2022 through April 2022?

A56. Yes. AES Indiana completed model runs to support the unit commitment decisions which document the prices used at that time. The prices used for the model runs consider observed ICE markets and power broker end of day marks. Confidential Attachment DJ-4 provides a summary and the model runs used for commitment decisions during each week of the February 2022 through April 2022 period.

Q57. In your opinion, was AES Indiana's operation of the Petersburg units during February 2022 through April 2022 reasonably aligned with market prices?

A57. Yes. During the historical FAC period all of the weekly 7-day model runs showed positive margin for Petersburg Units 2, 3, and 4. The units were offered as economic when available for dispatch except for four days when Petersburg Unit 2 was shown as must run returning from outages.

Q58. Please provide further detail on the unit commitment decisions in the February 2022 through April 2022 time period.

A58. AES Indiana ran a short-term model to track the economic value of the Petersburg Units and they were offered to MISO as economic, must run, or outage in the day ahead market. The model runs provided a 30 day forward look; we valued the coming weekend and week for evaluation of unit commitment (7-day period). These model runs are shown in Confidential Attachment DJ-4. Non-economic factors were also considered in unit commitment decisions, including reliability, price certainty, operational needs, and avoidance of startup costs. Below is the list of each unit's commitment decisions with commentary.

Petersburg Unit 2

Petersburg Unit 2 (“Unit 2”) entered the historical FAC period online and offered as economic to MISO. Unit 2 remained in that status through March 2 when the unit came off line for a tube leak repair. Unit 2 returned to service March 11 and was offered as must run while the unit was in startup. March 12 the unit was online and offered as economic to MISO and remained in that status through March 31. Unit 2 began a planned summer preparation outage on April 1, which lasted through April 7. The unit was offered as must run April 8 while in startup returning from outage. Petersburg Unit 2 was online and offered economic to MISO April 9 through 12 when the unit came offline for a tube leak repair. Unit 2 remained in outage April 13 through 26 to complete additional tube leaks that were found during the repair of the initial leak. Unit 2 was offered as Must run April 27 and 28 while returning from outage. On April 29 Unit 2 was online and offered as economic through the end of the historical FAC period.

Petersburg Unit 3

Petersburg Unit 3 (“Unit 3”) entered the start of the historical FAC period online and offered as economic to MISO. Unit 3 remained in that status through February 11 when the unit was offered as outage while repairing a scrubber rake and solids build up in the scrubber. Unit 3 was offered as outage February 12-14 but was able to remain on line running at minimum load while correcting the scrubber issue. The unit was online and offered as economic to MISO February 15 and remained in that status through March 10 when the unit came off line for a tube leak repair. Unit 3 returned to service and was online and offered as economic to MISO March 15. Unit 3 remained in that status until April 23 when the unit came offline for a planned maintenance outage. Unit 3 remained in that status through the end of the historical FAC period.

Petersburg Unit 4

Petersburg Unit 4 ("Unit 4") entered the historical FAC period online and offered as economic to MISO. Unit 4 remained in that status through February 7, when the unit came offline for repairs to replace the boiler circulating water pump. The unit remained in outage from February 8 through 14. Unit 4 returned to service and was online and offered as economic to MISO February 15. Unit 4 remained in that status through March 14, when the unit came offline to repair a tube leak. Unit 4 was offered as outage March 15 through March 27 when the unit returned to service. The unit was online and offered as economic to MISO from March 28 through April 17. The unit was forced offline on April 17 due to slag build up in the back pass that had to be removed. Repairs were completed April 23 and the unit returned to service and was online and offered as economic to MISO April 24 through the end of the historical FAC period.

Q59. Has AES Indiana performed a look back analysis to assess the economics of the Petersburg Station unit commitments for November 2021 through January 2022?

A59. Yes. As recognized in the Commission's FAC 127 Order, the Company does not have the benefit of hindsight when it makes its unit commitment decisions. Thus, the prudence of the unit commitment decisions should not be based on the hindsight analysis.

Q60. Why did you perform the look back analysis?

A60. We performed the analysis to provide robust information to the Commission. I would add that while the analysis should not be used to judge the prudence of the unit commitment decisions, the Company acknowledges that a look back analysis can inform our decision-making on a going forward basis and support our ongoing effort to improve our modeling and decision process.

Q61. Please discuss the look back analysis for February 2022 through April 2022.

A61. AES Indiana performed an evaluation of Petersburg for February 2022 through April 2022 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.

Petersburg receives a day ahead award from MISO for a specific number of MWhs at a specific price, during the real time dispatch period MISO will optimize the station by responding to real time prices. To optimize dispatch of the station, MISO may increase or decrease dispatch of the units above and below the day ahead awards. If dispatch is increased above the day ahead awards, additional "in the money" MWh will be sold. Conversely, if dispatch is reduced below day ahead awards, power is purchased at a lower LMP than cleared in the day ahead market and will have a positive margin to the benefit of our customers. MISO also has a mechanism for providing compensation to generators when MISO dispatches the station un-economically, called make whole payments.

AES Indiana holds Auction Revenue Rights and Financial Transmission Rights on the path from Petersburg to Indianapolis. These instruments exist for the purpose of paying back congestion that generation from Petersburg Locational Marginal Pricing Nodes experience due to AES Indiana's historic ownership of the transmission system at the start of the MISO energy market. All benefits from Financial Transmission Rights and Auction Revenue Rights are distributed to AES Indiana customers through the FAC process, effectively mitigating the congestion component of pricing for the Petersburg plants.

Similar to Financial Transmission Rights mitigating congestion, AES Indiana customers receive the benefit of Marginal Loss Credits to mitigate losses. All of these factors were included in the calculation of the table shown below.

Table DJ-4[1]
Petersburg Margin Look Back Analysis

	Pete 2	Pete 3	Pete 4	All Units
February	$ 7,153,706	$ 6,118,681	$ 7,970,848	$21,243,235
March	$ 5,052,148	$ 6,944,396	$ 5,201,727	$17,198,271
April	$ 3,000,089	$ 9,892,155	$ 9,906,584	$22,798,828
Total	$15,205,943	$22,955,231	$23,079,159	$61,240,334

Additionally, during the February 2022 through April 2022 period OSS margin was $10,573,914 all of which (100%) goes to the customer.

Q62. The Commission's June 3, 2020 Order in AES Indiana's FAC 127 (p. 8) noted "that it may be beneficial for AES Indiana to give some consideration in 'must run' decisions to short and longer term vantage points". Please respond.

A62. AES Indiana considers both the long and short term when making unit commitment decisions. First, in each FAC we present a forecast of fuel costs for the future FAC period (which here is September 2022 through November 2022). As stated above, 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.

As also discussed above, the Company does not commit the units based on the previous long term forecast (also referred to as the "vintage forecast"). As the "future period" becomes the "actual period" market pricing, protecting customers from price risk,

[1] Supporting detail for this table is included in Jackson Confidential Workpaper 1.

operational issues, and reliability will drive commitment decisions. In other words, the Company does not rely on the vintage forecast during the "actual" period. Rather, unit commitment decisions are based on circumstances as they exist during the actual period and energy market decisions are made through a nearer-term forward-looking assessment. Unit commitment decisions are not made a month or more in advance. A one-week forward-looking assessment of unit commitment economics is used as well as consideration of non-economic factors as discussed above. The application of this near term assessment process during the historical period of this FAC (February 2022 through April 2022) is shown in Confidential Attachment DJ-4.

AES Indiana is continuing to improve our understanding of market conditions and costs associated with "must run" and other unit commitment decisions. As discussed below, the more refined short term model the Company began using in May 2020 improves the economic view of unit commitment on a rolling 4-week period. Still important are non-economic factors such as predicted strong weather/high loads (hedge value), operational issues, and reliability, which will continued to be considered "must run" decisions.

PROJECTED COAL BURN, COAL PURCHASES AND COAL INVENTORY MANAGEMENT

Q63. Please update the Commission on AES Indiana's 2022 projected coal burn and coal purchases.

A63. Confidential Attachment DJ-5 shows the realized and projected monthly purchases and burns for 2022. The Company purchased coal for 2022 in July and purchased coal from an RFP in September 2021. Additional coal was purchased in December for 2022 delivery. Due to high natural gas prices coal burns have remained strong. Current inventory is within the target range. AES Indiana expects to build coal inventory to the high side of our target range throughout 2022 to have appropriate supply for winter of 2022-2023. AES Indiana will continue to closely monitor projected coal burns and manage inventories to ensure reliable coal supply. AES Indiana plans to discuss this subject in further detail with the OUCC during its FAC 136 audit.

Q64. Is AES Indiana's coal inventory within its target levels?

A64. Yes. AES Indiana inventory is currently within our 25-50 day supply of coal inventory target range.

Q65. What is AES Indiana doing to manage its inventory level?

A65. Although our inventory is currently within our target range, AES Indiana continues to actively manage its inventory levels. AES Indiana's long-term coal contracts often contain some variability in the quantity of coal that AES Indiana can take under that particular contract. That allows AES Indiana to increase deliveries when coal burns go up and decrease deliveries when coal burns go down. This contract variability is essential in managing the month-to-month variations in coal burns due to weather, market prices and unit availability. However, this contract variability is limited and may not alone be sufficient to follow highly volatile coal demands. If coal demand were to change dramatically, AES Indiana 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.

Current market conditions have created an extremely tight coal market. 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. AES Indiana does not expect to experience issues with coal supply that impacted last winter based on current purchases and burn projections.

Q66. Does decrement pricing impact the forecast or reconciliation in this FAC proceeding?

A66. No. There is no decrement pricing in the forecast period of September 2022 through November 2022 or in the historical FAC period of February 2022 through April 2022.

Q67. Has AES Indiana been impacted by any coal supply interruptions?

A67. No.

<u>EAGLE VALLEY CCGT OUTAGE</u>

Q68. What is the impact of the forced outage on the purchased power above the benchmark for FAC 136?

A68. Eagle Valley CCGT was in forced outage for a portion of the historical period from February 1 through March 17 The Eagle Valley CCGT was online March 18 and remained in that status for the remainder of the historical FAC period. The Company incurred purchased power costs over the benchmark of $498,872 during the FAC 136 historical period. The estimated portion of purchased power above the benchmark that could be attributable to the Eagle Valley outage was $293,356 as shown in <u>Attachment DJ-6</u>.

Q69. Has AES Indiana completed additional analysis outlining the impact of the Eagle Valley CCGT forced outage?

A69. Yes. As described in FAC 135 and FAC 133S1, the Company updated the actual realized commodity prices into the hourly production model and modeled Eagle Valley CCGT generation as if it had been operational. We then inserted the modeled Eagle Valley CCGT generation, day ahead awards, and fuel prices into the wholesale module in OATI and calculated the new costs as if Eagle Valley CCGT had been available on an hourly basis. OATI is the market interface system that AES Indiana uses to interact with the MISO market. OATI is used to submit bids, offers, track operations and market data and calculate shadow settlements to verify the MISO charges. OATI also contains a wholesale revenue module that calculates the MWh of wholesale sales and purchases from the market based on actual generation and then determines the wholesale revenue and production costs to ensure the lowest cost fuel goes to AES Indiana jurisdictional customers. We used the change in OATI results to determine the change in customer fuel and purchased power costs for each FAC during the outage period. The analysis for FAC 136 shows the total estimated Eagle Valley forced outage impact to fuel cost variances was $6,350,096 during the historical FAC 136 period, net of the February 2022 physical natural gas hedge benefit of $1,148,630. This analysis is presented in Attachment DJ-6.

Q70. Is Eagle Valley included in the forecast period of FAC 136?

A70. Yes. Eagle Valley is modeled to be available during the FAC 136 forecast period of September 2022 through November 2022.

Q71. Has AES Indiana taken steps to mitigate the power price risk of the Eagle Valley CCGT forced outage for AES Indiana customers?

A71. Yes. At the end of May, AES Indiana entered financial power hedges for peak power during the months of June through August of 2021. On June 18, 2021, AES Indiana entered financial peak power hedges for the month of September 2021. On September 29 and 30, 2021, AES Indiana entered financial peak power hedges for October 2021. On December 1, 2021, AES Indiana entered into a financial peak power hedge for December 6 through 17, 2021.

EAGLE VALLEY CCGT FINANCIAL POWER HEDGES

Q72. Did AES Indiana engage in peak power transactions as a result of the Eagle Valley CCGT outage during the FAC 136 reconciliation period?

A72. No. As discussed below, the Company elected to purchase natural gas instead of peak power to reduce risk for customers.

Q73. Please describe the hedging transaction completed for February through April 2022.

A73. For the month of February 2022, AES Indiana purchased 70,000 MMBtu/day of physical natural gas as an alternative to purchasing peak power hedges of 257 MW per day. 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. There were no hedge transactions for March or April 2022.

Q74. Has AES Indiana evaluated the benefit of using natural gas instead of purchased power during February 2022?

A74. Yes. As discussed in FAC 135, when evaluated versus daily index price for the natural gas delivery point associated with the hedge, AES realized a savings of $1,148,630 in February for our customers. We 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 our customer. This analysis can be seen on Attachment DJ-7 and shows the decision to hedge natural gas instead of power created a benefit of $1,892,244 in February for the customer.

Q75. Has AES Indiana included additional information regarding the completed hedging transactions as a part of its standard FAC audit package?

A75. Yes. AES Indiana's confidential FAC audit package provided to the OUCC includes the following types of information for the completed peak power hedging transactions: modeling to support hedge volumes, market pricing at the time of the transactions, and hedge settlement calculations. This confidential information provides additional details as to the facts and circumstances as they existed at the time the hedging transactions were entered into.

EAGLE VALLEY CCGT NATURAL GAS PRICE HEDGING

Q76. Did AES Indiana have any natural gas hedges for Eagle Valley CCGT during the historical FAC period of February through April 2022?

A76. Yes. As stated in FAC 135, with the expectation that the Eagle Valley CCGT outage would end early in November 2021, the Company transacted 75,000 MMBtu per day of physical natural gas for the December 2021, January 2022, and February 2022 delivery periods. The February hedges are reconciled in this FAC.

Q77. How were the hedges utilized?

A77. The physical natural gas hedges were utilized to support generation at Harding Street Station. The hedges provide certainty of price and because 50,000 MMBtu per day were transacted on the Rockies Express Pipeline, they added to firm capacity available to supply the station to supplement existing firm natural transport contracted on the Texas Gas Pipeline. Additionally, each of the physical natural gas contracts have "turn back" language allowing sell back of natural gas versus the daily index price if the Harding Street units are not committed and dispatched by MISO.

Q78. Were the natural gas hedging transactions reasonable based on the facts and circumstances as they existed at the times the transactions were entered into?

A78. Yes. At the time of the transactions, there was concern about building enough natural gas storage to support winter demand for heating and electric generation . Global demand for LNG and coal were extremely supportive of the domestic natural gas fundamentals and power fundamentals. AES Indiana elected to purchase natural gas for the December 2021 through February 2022 time period for the coldest part of winter to provide both reliability and price certainty for our customers. For price risk, operational needs, and fuel diversity, 50,000MMBtu/day were purchased on the Rockies Express (REX) pipeline with firm delivery and 25,000 MMBtu/day purchased on the Texas Gas pipeline in the Mainline Zone 1 pool which is transported on the firm capacity owned by AES Indiana. These purchases provided price certainty and utilizing the REX pipeline increased our firm capacity for natural gas to 154,000 MMBtu/day to support winter load. The extreme volatility in the existing natural gas market combined with the scarcity pricing experienced February 2021 made the decision to hedge fixed price natural gas for the current winter appropriate. Additionally, concern about the reliability of the MISO coal generation resources due to broadly low coal inventories added risk to fuel market volatility if significant cold were to develop over the winter.

Q79. What was the value of the natural gas hedges versus the realized daily pricing for February 2022?

A79. For evaluation of the hedges' economic settlement, the hedge price was compared to the daily index price for the natural gas delivery point associated with the hedges. In the month of February 2022, hedges on gas represented a cost of $3,876,875. Attachment DJ-8 included with this filing provides calculation detail. There were no associated transactional costs for the hedges.

Q80. What were the factors that impacted the values of the natural gas hedges?

A80. Natural gas prices were impacted by a mild weather during the start of the winter season. Inventory levels were able to move toward the five-year average and take pressure off the bullish fundamentals. There were no significant cold weather events during the December through and February periods which can lead to scarcity price spikes that add value to the hedges over a short period of time.

Q81. What was the customer benefit of the February 2022 natural gas hedges?

A81. As explained in FAC 122, the intent of the natural gas hedge is to mitigate customer exposure to natural gas price volatility. The hedges achieve this objective by providing price certainty for power generation. Winter hedges protect from scarcity events and protect from price volatility associated with high demand periods. Additionally, the natural gas hedges provide improved reliability of AES Indiana's natural gas fuel supply, lock in locational value fuel costs versus Henry Hub pricing, and reduces the need to purchase all of AES Indiana'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, the hedges did meet their objectives. During the month of February 2022, the Company 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. As prices realized at lower values, additional gas for generation was purchased at lower market pricing.

Q82. Did AES Indiana transact any natural gas financial hedges for the Eagle Valley CCGT during the February 2022 through April 2022 period?

A82. No.

Q83. Do the Company's FAC schedules separately identify the realized gains or losses from financial hedges, including any associated transactional costs, arising from AES Indiana's natural gas hedging plan?

A83. Yes, Attachment NHC-1, Schedule 5, Line 20 will be used to separately identify realized gains or losses. However, during this historical FAC period, there were no realized gains or losses from financial hedges and no transactional fees incurred for natural gas hedging.

Q84. Has AES Indiana included additional information regarding the completed hedging transactions as part of its standard FAC audit package?

A84. Yes. Consistent with my testimony in FAC 122, AES Indiana's confidential FAC audit package provided to the OUCC includes the following types of information for the completed hedging transactions: Eagle Valley projected burns; regional pricing (for example, daily index snapshots); market fundamentals (such as forecasted weather, gas production, gas storage levels, expected electric generation demand for gas); pipeline transport information (for example, forward locational gas prices); executed hedges (including transactional costs); and hedge exits (including profit and loss information). AES Indiana will show how the hedges cover burns at the Harding Street Station, specifically Harding Street Unit 7. This confidential information provides additional details as to the facts and circumstances as they existed at the time the hedging transactions were entered into.

<u>AES INDIANA LONG-TERM FUEL HEDGING – EAGLE VALLEY CCGT</u>

Q85. Has AES Indiana completed any natural gas transactions for the Eagle Valley CCGT under the fuel hedging policy approved in FAC 133?

A85. Yes. AES Indiana initiated the Long-Term Hedging Program for Eagle Valley on March 28, 2022. Once the plant was online and running as expected, the Company moved expeditiously and in accordance with the hedging plan to bring hedged volumes in line with approved guidelines. The Company expects to have all purchases made for the plan by the end of September 2022. <u>Attachment DJ-9</u> provides an evaluation of the hedges' economic settlement in April by comparing the hedge price to the daily index price for the natural gas delivery point associated with the hedges. In the month of April 2022, hedges on gas represented a savings of $523,275. <u>Confidential Attachment DJ-10</u> shows completed hedging transactions and remaining balances to be completed for the hedging policy approved in FAC 133. AES Indiana will provide hedging transactions, modeling to support hedge volumes, market pricing at the time of the transactions, and hedge settlement calculations in the confidential audit package provided to the OUCC and review the information in the FAC 136 audit.

<u>SHORT TERM MODEL</u>

Q86. Please discuss the short-term model AES Indiana uses to support and track the Petersburg unit commitment decisions.

A86. AES Indiana has created a short-term model on the Allegro risk management platform for Petersburg coal units. The model utilizes a combination of two types of trades to calculate the operating cost and potential margin for the Petersburg coal units. The two trades represent different aspects of the Petersburg units and combined provide a representation of the potential daily margin.

The first trade characterizes the minimum generation of each of the units and does so at a set cost. AES Indiana can break this down into different costs for on peak, off peak, and a 24-hour weekend run. This determines whether the unit has positive margin at minimum load with the expectation that the unit will not be at minimum over the peak hours of the day, hence the different heat rates for peak and off peak. For the weekend, AES Indiana calculates the cost for this trade assuming 12 hours of the unit at full load and 12 hours at minimum. This blended heat rate provides a reasonable expectation of cost over the course of a weekend day.

The second trade embodies the economic portion of the unit that can ramp up or down based on whether the unit is in the money during that timeframe. This is a spread option trade that is financial in nature. The trades work by comparing two "baskets" against each other. The first basket is the power price, adjusted for basis to the unit. The second basket considers the various factors that make up the cost to produce power for each individual unit. This includes coal cost, emissions, variable operation and maintenance costs, and heat rate. For this trade the heat rate used is at full load. The model runs daily Monday through Friday and takes these two baskets and compares them against each other.

There are additional considerations that AES Indiana has chosen to apply to the model as well. These are volatilities and correlations. A volatility measures how often and to what degree prices change measured as a percentage. A correlation shows how those prices move together, whether they often move together, or whether they do not have anything to do with one another. For example, coal and power have a very low correlation. Power will move without any corresponding change in coal. However, natural gas and power have a much stronger correlation. As natural gas prices move there are often corresponding changes in power price. These factors are then utilized to add additional nuance to the model. AES Indiana marks the power prices daily based on weather, load, and market information. These prices are loaded daily into the risk management system to feed update prices to the model.

AES Indiana makes other updates to the model monthly. Coal cost is adjusted based on its weighted average cost of inventory ("WACI") price. Also, for a short-term model AES Indiana believes that utilizing a shorter time horizon for power basis measurement is appropriate. Therefore, AES Indiana measures the power basis from Indiana Hub to Petersburg during the previous month and then applies that to the next month. This considers current conditions and potential congestion issues or load demand.

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 trades previously discussed. The total value of the two trades indicates if the unit is in or out of the money.

AES Indiana began using the model at the end of May 2020 and continues to use the model to support commitment decisions.

Q87. Will the Company make the model available to the OUCC during its FAC audit?

A87. AES Indiana will include model output from February 2022 through the end of April 2022 in the OUCC packet for review and will review the model and output with the OUCC during the audit as requested.

HARDING STREET STATION GAS SUPPLY EVALUATION

Q88. In Cause No. 45493, AES Indiana committed to provide further information on its evaluation of the firmness needs for gas supply at the Harding Street Station in a future FAC filing. Has AES Indiana completed this evaluation?

A88. Yes. AES Indiana completed this evaluation and has included it here as Confidential Attachment DJ-11.

CONCLUSION

Q89. What is your opinion as to whether AES Indiana acquires a reliable supply of fuel and generates and purchases power to achieve the lowest fuel cost reasonably possible?

A89. In my opinion, we have made every reasonable effort to acquire fuel and generate or purchase power or both to provide electricity to our retail customers at the lowest fuel cost reasonably possible. AES Indiana acknowledges that the Eagle Valley outage-related cost recovery remains subject to resolution of the pending FAC 133 sub docket.

Q90. Does this conclude your prefiled direct testimony?

A90. Yes.

Verification

I affirm under penalties for perjury that the foregoing representations are true to the best of my knowledge, information, and belief.

Dated this 17th day of June 2022.

David Jackson

AES Indiana

Calculation of Daily Benchmark

NYMEX Henry Hub Day Ahead Natural Gas Price

Day	Daily Average $/MMBtu	Transport Charges $/MMBtu	Proxy Gas Price $/MMBtu	Heat Rate BTU/KWH	Daily Benchmark $/MWH
1-Feb-22	5.5600	0.600	6.1600	12,500	77.00
2-Feb-22	5.4500	0.600	6.0500	12,500	75.63
3-Feb-22	6.7000	0.600	7.3000	12,500	91.25
4-Feb-22	5.8400	0.600	6.4400	12,500	80.50
5-Feb-22	5.3400	0.600	5.9400	12,500	74.25
6-Feb-22	5.3400	0.600	5.9400	12,500	74.25
7-Feb-22	5.3400	0.600	5.9400	12,500	74.25
8-Feb-22	4.4400	0.600	5.0400	12,500	63.00
9-Feb-22	4.3000	0.600	4.9000	12,500	61.25
10-Feb-22	4.1300	0.600	4.7300	12,500	59.13
11-Feb-22	4.0300	0.600	4.6300	12,500	57.88
12-Feb-22	4.0400	0.600	4.6400	12,500	58.00
13-Feb-22	4.0400	0.600	4.6400	12,500	58.00
14-Feb-22	4.0400	0.600	4.6400	12,500	58.00
15-Feb-22	4.0500	0.600	4.6500	12,500	58.13
16-Feb-22	4.3100	0.600	4.9100	12,500	61.38
17-Feb-22	4.3900	0.600	4.9900	12,500	62.38
18-Feb-22	4.5700	0.600	5.1700	12,500	64.63
19-Feb-22	4.6100	0.600	5.2100	12,500	65.13
20-Feb-22	4.6100	0.600	5.2100	12,500	65.13
21-Feb-22	4.6100	0.600	5.2100	12,500	65.13
22-Feb-22	4.6100	0.600	5.2100	12,500	65.13
23-Feb-22	4.4800	0.600	5.0800	12,500	63.50
24-Feb-22	4.5900	0.600	5.1900	12,500	64.88
25-Feb-22	4.7800	0.600	5.3800	12,500	67.25
26-Feb-22	4.6300	0.600	5.2300	12,500	65.38
27-Feb-22	4.6300	0.600	5.2300	12,500	65.38
28-Feb-22	4.6300	0.600	5.2300	12,500	65.38

Day	Daily Average $/MMBtu	Transport Charges $/MMBtu	Proxy Gas Price $/MMBtu	Heat Rate BTU/KWH	Daily Benchmark $/MWH
1-Mar-22	4.4600	0.600	5.0600	12,500	63.25
2-Mar-22	4.3600	0.600	4.9600	12,500	62.00
3-Mar-22	4.6500	0.600	5.2500	12,500	65.63
4-Mar-22	4.6300	0.600	5.2300	12,500	65.38
5-Mar-22	4.7400	0.600	5.3400	12,500	66.75
6-Mar-22	4.7400	0.600	5.3400	12,500	66.75
7-Mar-22	4.7400	0.600	5.3400	12,500	66.75
8-Mar-22	4.9300	0.600	5.5300	12,500	69.13
9-Mar-22	4.6100	0.600	5.2100	12,500	65.13
10-Mar-22	4.5500	0.600	5.1500	12,500	64.38
11-Mar-22	4.6500	0.600	5.2500	12,500	65.63
12-Mar-22	4.7900	0.600	5.3900	12,500	67.38
13-Mar-22	4.7900	0.600	5.3900	12,500	67.38
14-Mar-22	4.7900	0.600	5.3900	12,500	67.38
15-Mar-22	4.5900	0.600	5.1900	12,500	64.88
16-Mar-22	4.4600	0.600	5.0600	12,500	63.25
17-Mar-22	4.6800	0.600	5.2800	12,500	66.00
18-Mar-22	4.8000	0.600	5.4000	12,500	67.50
19-Mar-22	4.8700	0.600	5.4700	12,500	68.38
20-Mar-22	4.8700	0.600	5.4700	12,500	68.38
21-Mar-22	4.8700	0.600	5.4700	12,500	68.38
22-Mar-22	4.7700	0.600	5.3700	12,500	67.13
23-Mar-22	5.0000	0.600	5.6000	12,500	70.00
24-Mar-22	5.2600	0.600	5.8600	12,500	73.25
25-Mar-22	5.1900	0.600	5.7900	12,500	72.38
26-Mar-22	5.5100	0.600	6.1100	12,500	76.38
27-Mar-22	5.5100	0.600	6.1100	12,500	76.38
28-Mar-22	5.5100	0.600	6.1100	12,500	76.38
29-Mar-22	5.5200	0.600	6.1200	12,500	76.50
30-Mar-22	5.3200	0.600	5.9200	12,500	74.00
31-Mar-22	5.3200	0.600	5.9200	12,500	74.00

Day	Daily Average $/MMBtu	Transport Charges $/MMBtu	Proxy Gas Price $/MMBtu	Heat Rate BTU/KWH	Daily Benchmark $/MWH
1-Apr-22	5.4600	0.600	6.0600	12,500	75.75
2-Apr-22	5.4300	0.600	6.0300	12,500	75.38
3-Apr-22	5.4300	0.600	6.0300	12,500	75.38
4-Apr-22	5.4300	0.600	6.0300	12,500	75.38
5-Apr-22	5.7200	0.600	6.3200	12,500	79.00
6-Apr-22	5.9500	0.600	6.5500	12,500	81.88
7-Apr-22	6.2900	0.600	6.8900	12,500	86.13
8-Apr-22	6.0500	0.600	6.6500	12,500	83.13
9-Apr-22	6.3800	0.600	6.9800	12,500	87.25
10-Apr-22	6.3800	0.600	6.9800	12,500	87.25
11-Apr-22	6.3800	0.600	6.9800	12,500	87.25
12-Apr-22	6.3500	0.600	6.9500	12,500	86.88
13-Apr-22	6.5900	0.600	7.1900	12,500	89.88
14-Apr-22	6.6800	0.600	7.2800	12,500	91.00
15-Apr-22	6.9400	0.600	7.5400	12,500	94.25
16-Apr-22	6.9400	0.600	7.5400	12,500	94.25
17-Apr-22	6.9400	0.600	7.5400	12,500	94.25
18-Apr-22	6.9400	0.600	7.5400	12,500	94.25
19-Apr-22	7.4800	0.600	8.0800	12,500	101.00
20-Apr-22	7.4400	0.600	8.0400	12,500	100.50
21-Apr-22	7.1200	0.600	7.7200	12,500	96.50
22-Apr-22	6.8800	0.600	7.4800	12,500	93.50
23-Apr-22	6.5900	0.600	7.1900	12,500	89.88
24-Apr-22	6.5900	0.600	7.1900	12,500	89.88
25-Apr-22	6.5900	0.600	7.1900	12,500	89.88
26-Apr-22	6.4200	0.600	7.0200	12,500	87.75
27-Apr-22	6.8900	0.600	7.4900	12,500	93.63
28-Apr-22	6.9100	0.600	7.5100	12,500	93.88
29-Apr-22	6.9700	0.600	7.5700	12,500	94.63
30-Apr-22	6.8400	0.600	7.4400	12,500	93.00

AES Indiana
Purchased Power Above Daily Benchmark

	Operating Day	Total Cost of Hourly Purchases[1]	MWH Above the Daily Benchmark	Amount Above Daily Benchmark	IURC Order 43414 Methodology: Hourly Purchased Power Costs At-Risk After Consideration of MISO Economic Dispatch MW	Amount	Reasons	IURC Order 43414 Methodology: Non-Recoverable Balance Above Daily Benchmark MW	Amount
1	2/1/2022	$ 21,057	265	$ 652	-	$ -		-	$ -
2	2/5/2022	$ 53,444	707	$ 949	272	$ 424	Economic Purchases due to Unit Outages and Derates	-	$ -
3	2/6/2022	$ 24,576	293	$ 2,821	-	$ -		-	$ -
4	2/7/2022	$ 238,501	2,683	$ 39,288	25	$ 228	Economic Purchases due to Unit Outages and Derates	-	$ -
5	2/8/2022	$ 166,333	2,141	$ 31,450	837	$ 11,890	Economic Purchases due to Unit Outages and Derates	-	$ -
6	2/9/2022	$ 186,323	2,684	$ 21,928	768	$ 6,701	Economic Purchases due to Unit Outages and Derates	-	$ -
7	2/10/2022	$ 45,904	629	$ 8,712	150	$ 2,078	Economic Purchases due to Unit Outages and Derates	-	$ -
8	2/11/2022	$ 40,456	638	$ 3,528	159	$ 879	Economic Purchases due to Unit Outages and Derates	-	$ -
9	2/12/2022	$ 97,535	1,630	$ 2,995	958	$ 1,843	Economic Purchases due to Unit Outages and Derates	-	$ -
10	2/13/2022	$ 42,299	687	$ 2,453	-	$ -		-	$ -
11	2/14/2022	$ 64,311	924	$ 10,719	217	$ 2,625	Economic Purchases due to Unit Outages and Derates	-	$ -
12	2/15/2022	$ 3,644	58	$ 272	-	$ -		-	$ -
13	2/18/2022	$ 95,682	1,342	$ 8,948	350	$ 613	Economic Purchases due to Unit Outages and Derates	-	$ -
14	2/20/2022	$ 340,474	3,756	$ 95,845	401	$ 116	Economic Purchases due to Unit Outages	-	$ -
15	2/23/2022	$ 108,661	1,370	$ 21,666	-	$ -		-	$ -
16	2/25/2022	$ 22,379	287	$ 3,078	-	$ -		-	$ -
17	2/28/2022	$ 8,114	91	$ 2,165	-	$ -		-	$ -
	Feb Total		20,185	$ 257,470	4,137	$ 27,396		-	$ -
18	3/3/2022	$ 161,054	1,956	$ 32,682	-	$ -		-	$ -
19	3/4/2022	$ 102,215	1,545	$ 1,203	-	$ -		-	$ -
20	3/9/2022	$ 53,164	731	$ 5,553	124	$ 1,132	Economic Purchases due to Unit Outages	-	$ -
21	3/10/2022	$ 65,265	891	$ 7,902	315	$ 3,590	Economic Purchases due to Unit Outages	-	$ -
22	3/11/2022	$ 138,539	2,029	$ 5,375	592	$ 1,165	Economic Purchases due to Unit Outages	-	$ -
23	3/12/2022	$ 609,262	8,485	$ 37,543	3,695	$ 16,726	Economic Purchases due to Unit Outages	-	$ -
24	3/13/2022	$ 290,197	2,525	$ 120,062	1,673	$ 86,732	Economic Purchases due to Unit Outages	-	$ -
25	3/15/2022	$ 2,234	34	$ 28	-	$ -		-	$ -
26	3/16/2022	$ 41,882	568	$ 5,956	-	$ -		-	$ -
27	3/18/2022	$ 3,886	43	$ 984	-	$ -		-	$ -
28	3/21/2022	$ 11,505	60	$ 7,402	-	$ -		-	$ -
29	3/23/2022	$ 92	1	$ 22	-	$ -		-	$ -
	Mar Total		18,868	$ 224,712	6,399	$ 109,344		-	$ -
30	4/18/2022	$ 60,319	475	$ 15,550	-	$ -		-	$ -
31	4/19/2022	$ 7,377	64	$ 913	64	$ 913	Economic Purchases due to Unit Outages	-	$ -
32	4/23/2022	$ 11,413	126	$ 88	-	$ -		-	$ -
33	4/24/2022	$ 11,464	126	$ 139	-	$ -		-	$ -
	Apr Total		791	$ 16,691	64	$ 913		-	$ -
	Grand Total			$ 498,872		$ 137,653			$ -

[1]This column is the total cost of purchased power for those hours during the operating day when the price was above the benchmark.

AES Indiana

Calculation of Daily Benchmark

NYMEX Henry Hub Day Ahead Natural Gas Price

Day	Daily Average $/MMBtu	Transport Charges $/MMBtu	Proxy Gas Price $/MMBtu	Heat Rate BTU/KWH	Daily Benchmark $/MWH
1-Feb-22	5.5600	0.600	6.1600	12,500	77.00
2-Feb-22	5.4500	0.600	6.0500	12,500	75.63
3-Feb-22	6.7000	0.600	7.3000	12,500	91.25
4-Feb-22	5.8400	0.600	6.4400	12,500	80.50
5-Feb-22	5.3400	0.600	5.9400	12,500	74.25
6-Feb-22	5.3400	0.600	5.9400	12,500	74.25
7-Feb-22	5.3400	0.600	5.9400	12,500	74.25
8-Feb-22	4.4400	0.600	5.0400	12,500	63.00
9-Feb-22	4.3000	0.600	4.9000	12,500	61.25
10-Feb-22	4.1300	0.600	4.7300	12,500	59.13
11-Feb-22	4.0300	0.600	4.6300	12,500	57.88
12-Feb-22	4.0400	0.600	4.6400	12,500	58.00
13-Feb-22	4.0400	0.600	4.6400	12,500	58.00
14-Feb-22	4.0400	0.600	4.6400	12,500	58.00
15-Feb-22	4.0500	0.600	4.6500	12,500	58.13
16-Feb-22	4.3100	0.600	4.9100	12,500	61.38
17-Feb-22	4.3900	0.600	4.9900	12,500	62.38
18-Feb-22	4.5700	0.600	5.1700	12,500	64.63
19-Feb-22	4.6100	0.600	5.2100	12,500	65.13
20-Feb-22	4.6100	0.600	5.2100	12,500	65.13
21-Feb-22	4.6100	0.600	5.2100	12,500	65.13
22-Feb-22	4.6100	0.600	5.2100	12,500	65.13
23-Feb-22	4.4800	0.600	5.0800	12,500	63.50
24-Feb-22	4.5900	0.600	5.1900	12,500	64.88
25-Feb-22	4.7800	0.600	5.3800	12,500	67.25
26-Feb-22	4.6300	0.600	5.2300	12,500	65.38
27-Feb-22	4.6300	0.600	5.2300	12,500	65.38
28-Feb-22	4.6300	0.600	5.2300	12,500	65.38

Day	Daily Average $/MMBtu	Transport Charges $/MMBtu	Proxy Gas Price $/MMBtu	Heat Rate BTU/KWH	Daily Benchmark $/MWH
1-Mar-22	4.4600	0.600	5.0600	12,500	63.25
2-Mar-22	4.3600	0.600	4.9600	12,500	62.00
3-Mar-22	4.6500	0.600	5.2500	12,500	65.63
4-Mar-22	4.6300	0.600	5.2300	12,500	65.38
5-Mar-22	4.7400	0.600	5.3400	12,500	66.75
6-Mar-22	4.7400	0.600	5.3400	12,500	66.75
7-Mar-22	4.7400	0.600	5.3400	12,500	66.75
8-Mar-22	4.9300	0.600	5.5300	12,500	69.13
9-Mar-22	4.6100	0.600	5.2100	12,500	65.13
10-Mar-22	4.5500	0.600	5.1500	12,500	64.38
11-Mar-22	4.6500	0.600	5.2500	12,500	65.63
12-Mar-22	4.7900	0.600	5.3900	12,500	67.38
13-Mar-22	4.7900	0.600	5.3900	12,500	67.38
14-Mar-22	4.7900	0.600	5.3900	12,500	67.38
15-Mar-22	4.5900	0.600	5.1900	12,500	64.88
16-Mar-22	4.4600	0.600	5.0600	12,500	63.25
17-Mar-22	4.6800	0.600	5.2800	12,500	66.00
18-Mar-22	4.8000	0.600	5.4000	12,500	67.50
19-Mar-22	4.8700	0.600	5.4700	12,500	68.38
20-Mar-22	4.8700	0.600	5.4700	12,500	68.38
21-Mar-22	4.8700	0.600	5.4700	12,500	68.38
22-Mar-22	4.7700	0.600	5.3700	12,500	67.13
23-Mar-22	5.0000	0.600	5.6000	12,500	70.00
24-Mar-22	5.2600	0.600	5.8600	12,500	73.25
25-Mar-22	5.1900	0.600	5.7900	12,500	72.38
26-Mar-22	5.5100	0.600	6.1100	12,500	76.38
27-Mar-22	5.5100	0.600	6.1100	12,500	76.38
28-Mar-22	5.5100	0.600	6.1100	12,500	76.38
29-Mar-22	5.5200	0.600	6.1200	12,500	76.50
30-Mar-22	5.3200	0.600	5.9200	12,500	74.00
31-Mar-22	5.3200	0.600	5.9200	12,500	74.00

Day	Daily Average $/MMBtu	Transport Charges $/MMBtu	Proxy Gas Price $/MMBtu	Heat Rate BTU/KWH	Daily Benchmark $/MWH
1-Apr-22	5.4600	0.600	6.0600	12,500	75.75
2-Apr-22	5.4300	0.600	6.0300	12,500	75.38
3-Apr-22	5.4300	0.600	6.0300	12,500	75.38
4-Apr-22	5.4300	0.600	6.0300	12,500	75.38
5-Apr-22	5.7200	0.600	6.3200	12,500	79.00
6-Apr-22	5.9500	0.600	6.5500	12,500	81.88
7-Apr-22	6.2900	0.600	6.8900	12,500	86.13
8-Apr-22	6.0500	0.600	6.6500	12,500	83.13
9-Apr-22	6.3800	0.600	6.9800	12,500	87.25
10-Apr-22	6.3800	0.600	6.9800	12,500	87.25
11-Apr-22	6.3800	0.600	6.9800	12,500	87.25
12-Apr-22	6.3500	0.600	6.9500	12,500	86.88
13-Apr-22	6.5900	0.600	7.1900	12,500	89.88
14-Apr-22	6.6800	0.600	7.2800	12,500	91.00
15-Apr-22	6.9400	0.600	7.5400	12,500	94.25
16-Apr-22	6.9400	0.600	7.5400	12,500	94.25
17-Apr-22	6.9400	0.600	7.5400	12,500	94.25
18-Apr-22	6.9400	0.600	7.5400	12,500	94.25
19-Apr-22	7.4800	0.600	8.0800	12,500	101.00
20-Apr-22	7.4400	0.600	8.0400	12,500	100.50
21-Apr-22	7.1200	0.600	7.7200	12,500	96.50
22-Apr-22	6.8800	0.600	7.4800	12,500	93.50
23-Apr-22	6.5900	0.600	7.1900	12,500	89.88
24-Apr-22	6.5900	0.600	7.1900	12,500	89.88
25-Apr-22	6.5900	0.600	7.1900	12,500	89.88
26-Apr-22	6.4200	0.600	7.0200	12,500	87.75
27-Apr-22	6.8900	0.600	7.4900	12,500	93.63
28-Apr-22	6.9100	0.600	7.5100	12,500	93.88
29-Apr-22	6.9700	0.600	7.5700	12,500	94.63
30-Apr-22	6.8400	0.600	7.4400	12,500	93.00

AES Indiana
Purchased Power Above Daily Benchmark

Cause No. 38703 FAC 136
Attachment DJ-3

	Operating Day	Total Cost of Hourly Purchases[1]	MWH Above the Daily Benchmark	Amount Above Daily Benchmark	IURC Order 43414 Methodology: Hourly Purchased Power Costs At-Risk After Consideration of MISO Economic Dispatch MW	Amount	Reasons	IURC Order 43414 Methodology: Non-Recoverable Balance Above Daily Benchmark MW	Amount
1	2/1/2022	$ 21,057	265	$ 652	-	$ -		-	$ -
2	2/5/2022	$ 53,444	707	$ 949	272	$ 424	Economic Purchases due to Unit Outages and Derates	41	$ 64
3	2/6/2022	$ 24,576	293	$ 2,821	-	$ -		-	$ -
4	2/7/2022	$ 238,501	2,683	$ 39,288	25	$ 228	Economic Purchases due to Unit Outages and Derates	4	$ 34
5	2/8/2022	$ 166,333	2,141	$ 31,450	837	$ 11,890	Economic Purchases due to Unit Outages and Derates	42	$ 388
6	2/9/2022	$ 186,323	2,684	$ 21,928	768	$ 6,701	Economic Purchases due to Unit Outages and Derates	-	$ -
7	2/10/2022	$ 45,904	629	$ 8,712	150	$ 2,078	Economic Purchases due to Unit Outages and Derates	-	$ -
8	2/11/2022	$ 40,456	638	$ 3,528	159	$ 879	Economic Purchases due to Unit Outages and Derates	-	$ -
9	2/12/2022	$ 97,535	1,630	$ 2,995	958	$ 1,843	Economic Purchases due to Unit Outages and Derates	-	$ -
10	2/13/2022	$ 42,299	687	$ 2,453	-	$ -		-	$ -
11	2/14/2022	$ 64,311	924	$ 10,719	217	$ 2,625	Economic Purchases due to Unit Outages and Derates	33	$ 394
12	2/15/2022	$ 3,644	58	$ 272	-	$ -		-	$ -
13	2/18/2022	$ 95,682	1,342	$ 8,948	350	$ 613	Economic Purchases due to Unit Outages and Derates	53	$ 92
14	2/20/2022	$ 340,474	3,756	$ 95,845	401	$ 116	Economic Purchases due to Unit Outages	-	$ -
15	2/23/2022	$ 108,661	1,370	$ 21,666	-	$ -		-	$ -
16	2/25/2022	$ 22,379	287	$ 3,078	-	$ -		-	$ -
17	2/28/2022	$ 8,114	91	$ 2,165	-	$ -		-	$ -
	Feb Total		20,185	$ 257,470	4,137	$ 27,396		171	$ 972
18	3/3/2022	$ 161,054	1,956	$ 32,682	-	$ -		-	$ -
19	3/4/2022	$ 102,215	1,545	$ 1,203	-	$ -		-	$ -
20	3/9/2022	$ 53,164	731	$ 5,553	124	$ 1,132	Economic Purchases due to Unit Outages	-	$ -
21	3/10/2022	$ 65,265	891	$ 7,902	315	$ 3,590	Economic Purchases due to Unit Outages	-	$ -
22	3/11/2022	$ 138,539	2,029	$ 5,375	592	$ 1,165	Economic Purchases due to Unit Outages	-	$ -
23	3/12/2022	$ 609,262	8,485	$ 37,543	3,695	$ 16,726	Economic Purchases due to Unit Outages	-	$ -
24	3/13/2022	$ 290,197	2,525	$ 120,062	1,673	$ 86,732	Economic Purchases due to Unit Outages	-	$ -
25	3/15/2022	$ 2,234	34	$ 28	-	$ -		-	$ -
26	3/16/2022	$ 41,882	568	$ 5,956	-	$ -		-	$ -
27	3/18/2022	$ 3,886	43	$ 984	-	$ -		-	$ -
28	3/21/2022	$ 11,505	60	$ 7,402	-	$ -		-	$ -
29	3/23/2022	$ 92	1	$ 22	-	$ -		-	$ -
	Mar Total		18,868	$ 224,712	6,399	$ 109,344		-	$ -
30	4/18/2022	$ 60,319	475	$ 15,550	-	$ -		-	$ -
31	4/19/2022	$ 7,377	64	$ 913	64	$ 913	Economic Purchases due to Unit Outages	-	$ -
32	4/23/2022	$ 11,413	126	$ 88	-	$ -		-	$ -
33	4/24/2022	$ 11,464	126	$ 139	-	$ -		-	$ -
	Apr Total		791	$ 16,691	64	$ 913		-	$ -
	Grand Total			$ 498,872		$ 137,653			$ 972

[1]This column is the total cost of purchased power for those hours during the operating day when the price was above the benchmark.

CONFIDENTIAL ATTACHMENT DJ-4

[CONFIDENTIAL – NOT REPRODUCED HEREIN]

CONFIDENTIAL ATTACHMENT DJ-5

[CONFIDENTIAL – NOT REPRODUCED HEREIN]

AES Indiana
Estimated Impact of Eagle Valley Forced Outage

	As Filed Variance	Estimated Non Outage Results (2)	Eagle Valley Impact
FAC133	$ 13,683,621	$ 7,032,886	$ 6,650,735
FAC134	$ 32,281,690	$ 27,356,531	$ 4,925,159
FAC135	$ 64,326,816	$ 40,734,330	$ 23,592,486
FAC 136 (1)	$ 12,378,189	$ 6,028,093	$ 6,350,096
		$ 81,151,841	$ 41,518,476
less 50% FAC133 already recovered		$ 6,841,811	
		$ 74,310,030	

Value of Power and Fuel Hedges	
$ 1,590,974	gain
$ 5,635,472	gain
$ (195,109)	loss
$ 1,148,630	gain
$ 8,179,967	net

(1) Outage ended on March 18, 2022 therefore only includes the months of February and March 2022.
(2) Estimated results if EV had been available

Purchase Power Over Benchmark (Source: Attachments DJ-2)

	Total Purchased Power over Benchmark	Non Outage Purchases over Benchmark	Eagle Valley Impact
FAC133	$1,198,183	$161,097	$1,037,085
FAC134 (1)	$1,183,609	$133,349	$1,050,260
FAC135	$2,487,937	$273,441	$2,214,496
FAC136	$498,872	$205,516	$293,356
	$5,368,601	$773,404	$4,595,198

(1) FAC 134 total of $1,271,874 plus October tie line true-up of ($88,265)

Deferred Variances

	Reconciliation Period	Deferred	In Proposed Factors	Cumulative Deferral
FAC133	May - Jul 2021	$13,683,621	$6,841,811	$6,841,810
FAC134	Aug - Oct 2021	$32,281,690	$0	$39,123,500
FAC135	Nov 2021 - Jan 2022	$64,326,816	$34,140,968	$69,309,348
FAC136	Feb - Apr 2022	$12,378,189	$40,169,062	$41,518,475
		$122,670,316	$81,151,841	

AES INDIANA
Comparison of Actual and Estimated Cost of Fuel

Line No.	Description	FAC 133 May-21 Actual	FAC 133 May-21 Non Outage Actuals	FAC 133 May-21 Eagle Valley Impact	FAC 133 June-21 Actual	FAC 133 June-21 Non Outage Actuals	FAC 133 June-21 Eagle Valley Impact	FAC 133 July-21 Actual	FAC 133 July-21 Non Outage Actuals	FAC 133 July-21 Eagle Valley Impact	FAC 133 TOTAL Actual	FAC 133 TOTAL Non Outage Actuals	FAC 133 TOTAL Eagle Valley Impact
	Fuel Cost												
15	Coal and Oil Generation	12,947,434	12,947,434	-	14,566,015	14,566,015	-	16,170,366	16,170,366	-	43,683,815	43,683,815	-
18	Other Generation - Internal Combustion	1,850	1,850	-	1,565	1,565	-	1,932	1,932	-	5,347	5,347	-
19	Natural Gas Generation	3,812,298	10,744,527	6,932,229	8,382,253	15,594,011	7,211,758	9,964,055	18,602,236	8,638,181	22,158,606	44,940,774	22,782,168
	Financial Hedges Gains/Losses & Transactional Fees			-	(758,807)	-	758,807	(832,167)	-	832,167	(1,590,974)	-	1,590,974
	Purchases through MISO			-			-			-	-	-	-
21	Non-Wind PPA Market Purchases	6,861,548	1,205,483	(5,656,065)	8,564,046	2,145,734	(6,418,312)	8,991,144	2,210,452	(6,780,692)	24,416,738	5,561,669	(18,855,069)
											-	-	-
	LESS:										-	-	-
											-	-	-
25	Inter-System Sales through MISO	46,933	3,572,542	3,525,609	292,850	3,810,447	3,517,597	395,817	4,739,848	4,344,031	735,600	12,122,836	11,387,236
28	Transmission Losses	9,799	191,517	181,718	60,408	260,872	200,464	87,000	296,564	209,564	157,207	748,954	591,747
29	Lakefield PPA Adjustment	6,116	116,794	110,678	13,128	155,875	142,747	35,132	209,398	174,266	54,376	482,066	427,690
30	Purchased Power in Excess	-	-	-	-	-	-	-	-	-	-	-	-
		$ -											
31	Total Fuel Costs (F)	$ 31,329,621	$ 28,787,781	$ (2,541,840)	$ 37,449,967	$ 35,141,411	$ (2,308,556)	$ 40,062,602	$ 38,024,397	$ (2,038,205)	$ 108,842,190	$ 101,953,590	$ (6,888,600)
32	F / S (Mills/kWh)	33.832	31.087	-8%	33.744	31.664	-6%	33.724	32.008	-5%	33.762	31.625	-6%
SCHEDULE 4													
	BILLED SALES	882,944	882,944		1,054,335	1,054,335		1,185,336	1,185,336		3,122,615	3,122,615	
	ACTUAL COST OF FUEL INCURRED	$ 29,871,761	$ 27,448,080		$ 35,577,480	$ 33,384,463		$ 39,974,271	$ 37,940,235		$ 105,423,513	$ 98,772,778	
	COST OF FUEL IN BASE RATES	$ 29,082,409	$ 29,082,409		$ 34,727,686	$ 34,727,686		$ 39,042,597	$ 39,042,597		$ 102,852,693	$ 102,852,693	
	INCREMENTAL COST OF FUEL	$ 789,352	$ (1,634,329)		$ 849,794	$ (1,343,223)		$ 931,674	$ (1,102,362)		$ 2,570,820	$ (4,079,915)	
											$ -	$ -	
	COST OF FUEL BILLED	$ (1,680,680)	$ (1,680,680)		$ (4,378,662)	$ (4,378,662)		$ (5,053,459)	$ (5,053,459)		$ (11,112,801)	$ (11,112,801)	
		$ 2,470,032	$ 46,351		$ 5,228,456	$ 3,035,439		$ 5,985,133	$ 3,951,097		$ 13,683,621	$ 7,032,886	
	Schedule 4 Variance	$ 2,470,032	$ 46,351	$ (2,423,681)	$ 5,228,456	$ 3,035,439	$ (2,193,017)	$ 5,985,133	$ 3,951,097	$ (2,034,037)	$ 13,683,621	$ 7,032,886	$ (6,650,735)
	PURCHASED POWER OVER BENCHMARK	$ 589,655	$ 73,309	$ (516,346)	$ 405,772	$ 58,956	$ (346,815)	$ 202,756	$ 28,832	$ (173,924)	$ 1,198,183	$ 161,097	$ (1,037,085)

AES INDIANA
Comparison of Actual and Estimated Cost of Fuel

Line No.	Description	Aug-21	FAC 134		Sept-21	FAC 134		October-21	FAC 134		TOTAL	FAC 134	
		Actual	Non Outage Actuals	Eagle Valley Impact	Actual	Non Outage Actuals	Eagle Valley Impact	Actual	Non Outage Actuals	Eagle Valley Impact	Actual	Non Outage Actuals	Eagle Valley Impact
	Fuel Cost												
19	Natural Gas Generation	14,459,213	$ 24,383,315	9,924,102	8,234,683	$ 18,929,360	10,694,677	13,977,551	30,956,459	16,978,908	36,671,447	74,269,133	37,597,686
	Financial Hedges Gains/Losses & Transactional I	(2,080,504)	$ -	2,080,504	(1,953,922)	$ -	1,953,922	(1,601,046)	-	1,601,046	(5,635,472)	-	5,635,472
21	Non-Wind PPA Market Purchases	5,095,128	$ 726,624	(4,368,504)	9,512,983	$ 2,166,135	(7,346,848)	15,160,506	871,428	(14,289,078)	29,768,617	3,764,187	(26,004,430)
	LESS:												
25	Inter-System Sales through MISO	1,055,312	$ 7,899,208	6,843,896	141,081	$ 5,552,280	5,411,199	899,652	8,767,113	7,867,461	2,096,045	22,218,601	20,122,556
28	Transmission Losses	227,063	$ 494,629	267,566	32,517	$ 302,156	269,639	31,103	238,012	206,909	290,683	1,034,797	744,114
29	Lakefield PPA Adjustment	58,681	$ 273,498	214,817	19,532	$ 337,963	318,431	49,015	399,728	350,713	127,228	1,011,188	883,960
30	Purchased Power in Excess	-	$ -	-	-	$ -	-	-	-	-	-	-	-
31	Total Fuel Costs (F)	$ 41,491,404	$ 41,801,227	$ 309,822	$ 39,307,315	$ 38,609,798	$ (697,517)	$ 48,003,421	$ 43,869,214	$ (4,134,207)	$ 128,802,140	$ 124,280,238	$ (4,521,902)
32	F / S (Mills/kWh)	33.114	33.361	1%	38.295	37.615	-2%	51.165	46.759	-9%	49.622		-4%
SCHEDULE 4													
	BILLED SALES	1,209,854	1,209,854		1,213,863	1,213,863		998,313	998,313		3,422,030	3,422,030	
	ACTUAL COST OF FUEL INCURRED	$ 40,063,105	$ 40,361,939		$ 46,484,884	$ 45,659,457		$ 51,078,685	$ 46,680,118		$ 137,626,674	$ 132,701,514	
	COST OF FUEL IN BASE RATES	$ 39,850,171	$ 39,850,171		$ 39,982,219	$ 39,982,219		$ 32,882,434	$ 32,882,434		$ 112,714,824	$ 112,714,824	
	INCREMENTAL COST OF FUEL	$ 212,934	$ 511,768		$ 6,502,664	$ 5,677,237		$ 18,196,251	$ 13,797,684		$ 24,911,849	$ 19,986,689	
											$ -	$ -	
	COST OF FUEL BILLED	$ (5,201,682)	$ (5,201,682)		$ (1,079,042)	$ (1,079,042)		$ (1,089,118)	$ (1,089,118)		$ (7,369,842)	$ (7,369,842)	
		$ 5,414,616	$ 5,713,450		$ 7,581,706	$ 6,756,279		$ 19,285,369	$ 14,886,802		$ 32,281,690	$ 27,356,531	
	Schedule 4 Variance	$ 5,414,616	$ 5,713,450	$ 298,834	$ 7,581,706	$ 6,756,279	$ (825,427)	$ 19,285,369	$ 14,886,802	$ (4,398,567)	$ 32,281,690	$ 27,356,531	$ (4,925,159)
	PURCHASED POWER OVER BENCHMARK	$ 380,761	$ 174	$ (380,587)	$ 246,003	$ 1,621	$ (244,382)	$ 556,845	$ 131,554	$ (425,291)	$ 1,183,609	$ 133,349	$ (1,050,260)

AES INDIANA
Comparison of Actual and Estimated Cost of Fuel

Line No.	Description	FAC 135 November-21 Actual	FAC 135 Non Outage Actuals	FAC 135 Eagle Valley Impact	FAC 135 December-21 Actual	FAC 135 Non Outage Actuals	FAC 135 Eagle Valley Impact	FAC 135 January-2022 Actual	FAC 135 Non Outage Actuals	FAC 135 Eagle Valley Impact	FAC 135 TOTAL Actual	FAC 135 Non Outage Actuals	FAC 135 Eagle Valley Impact
1	Coal and Oil Generation	184,482		(184,482)	623,008		(623,008)	913,115		(913,115)	1,720,605	-	(1,720,605)
2	Nuclear Generation	-		-	-		-	-		-	-	-	-
3	Hydro Generation	-		-	-		-	-		-	-	-	-
4	Other Generation - Internal Combustion	19		(19)	15		(15)	14		(14)	48	-	(48)
5	Natural Gas Generation	382,977		(382,977)	211,212		(211,212)	273,678		(273,678)	867,867	-	(867,867)
	Purchases through MISO			-			-			-	-	-	-
6	Wind Purchase Power Agreement Purchases	59,790		(59,790)	74,863		(74,863)	90,717		(90,717)	225,370	-	(225,370)
7	Non-Wind PPA Market Purchases	427,674		(427,674)	226,904		(226,904)	141,264		(141,264)	795,842	-	(795,842)
8	Other	19		(19)	14		(14)	280		(280)	313	-	(313)
9	Purchased Power other than MISO	7,585		(7,585)	6,768		(6,768)	7,292		(7,292)	21,645	-	(21,645)
	LESS:			-			-			-	-	-	-
10	Energy Losses and Company Use	52,802		(52,802)	56,393		(56,393)	66,608		(66,608)	175,803	-	(175,803)
11	Inter-System Sales through MISO	-		-	10,527		(10,527)	44,636		(44,636)	55,163	-	(55,163)
12	Inter-System Sales other than MISO	-		-	-		-	-		-	-	-	-
13	Non-Jurisdictional Retail Sales	-		-	-		-	-		-	-	-	-
14	Sales (S)	1,009,744	-	(1,009,744)	1,075,864	-	(1,075,864)	1,315,116	-	(1,315,116)	3,400,724	-	(3,400,724)
	Fuel Cost												
15	Coal and Oil Generation	4,974,914	4,974,914	-	14,770,615	14,770,615	-	23,001,892	23,001,892	-	42,747,421	42,747,421	-
16	Nuclear Generation	-	-	-	-	-	-	-	-	-	-	-	-
17	Hydro Generation	-	-	-	-	-	-	-	-	-	-	-	-
18	Other Generation - Internal Combustion	2,954	2,954	-	1,009	1,009	-	2,203	2,203	-	6,166	6,166	-
19	Natural Gas Generation	24,572,739	40,248,921	15,676,182	15,481,539	27,228,295	11,746,756	20,227,469	34,151,474	13,924,005	60,281,747	101,628,689	41,346,942
	Financial Hedges Gains/Losses & Transactional I	-	-	-	482,546	-	(482,546)	-	-	-	482,546	-	(482,546)
	Purchases through MISO												
20	Wind Purchase Power Agreement Purchases	7,929,986	7,929,986	-	7,483,356	7,483,356	-	8,162,108	8,162,108	-	23,575,450	23,575,450	-
21	Non-Wind PPA Market Purchases	27,481,782	1,978,799	(25,502,983)	9,524,139	251,415	(9,272,724)	7,659,290	413,318	(7,245,972)	44,665,211	2,643,532	(42,021,679)
22	Other	472	472	-	337	337	-	6,673	6,673	-	7,482	7,482	-
23	MISO Components of Cost of Fuel	7,081,450	7,081,450	-	2,546,715	2,546,715	-	1,516,613	1,516,613	-	11,144,778	11,144,778	-
24	Purchased Power other than MISO	1,225,785	1,225,785	-	1,112,262	1,112,262	-	1,086,815	1,086,815	-	3,424,862	3,424,862	-
	LESS:												
25	Inter-System Sales through MISO	-	3,544,069	3,544,069	331,296	7,679,564	7,348,268	1,875,771	12,246,313	10,370,542	2,207,067	23,469,946	21,262,879
28	Transmission Losses	-	272,945	272,945	40,793	315,258	274,465	212,251	467,751	255,500	253,044	1,055,954	802,910
29	Lakefield PPA Adjustment	68	263,961	263,893	10,114	580,567	570,453	267,375	1,573,346	1,305,971	277,557	2,417,874	2,140,317
30	Purchased Power in Excess	-	-	-	-	-	-	-	-	-	-	-	-
		$ -											
31	Total Fuel Costs (F)	$ 73,270,014	$ 59,362,306	$ (13,907,708)	$ 51,020,315	$ 44,818,614	$ (6,201,701)	$ 59,307,666	$ 54,053,686	$ (5,253,980)	$ 183,597,995	$ 158,234,607	$ (25,363,388)
32	F / S (Mills/kWh)	72.563	58.789	-19%	47.423	41.658	-12%	45.097	41.102	-9%	53.988	46.530	
SCHEDULE 4													
	BILLED SALES	904,955	904,955		1,088,734	1,088,734		1,214,289	1,214,289		3,207,978	3,207,978	
	ACTUAL COST OF FUEL INCURRED	$ 65,666,249	$ 53,201,399		$ 51,631,032	$ 45,354,481		$ 54,760,791	$ 49,909,706		$ 172,058,072	$ 148,465,587	
	COST OF FUEL IN BASE RATES	$ 29,807,408	$ 29,807,408		$ 35,860,720	$ 35,860,720		$ 39,996,251	$ 39,996,251		$ 105,664,379	$ 105,664,379	
	INCREMENTAL COST OF FUEL	$ 35,858,841	$ 23,393,992		$ 15,770,312	$ 9,493,760		$ 14,764,540	$ 9,913,455		$ 66,393,693	$ 42,801,208	
											$ -	$ -	
	COST OF FUEL BILLED	$ (1,085,010)	$ (1,085,010)		$ 1,152,041	$ 1,152,041		$ 1,999,847	$ 1,999,847		$ 2,066,878	$ 2,066,878	
		$ 36,943,851	$ 24,479,002		$ 14,618,271	$ 8,341,719		$ 12,764,694	$ 7,913,608		$ 64,326,816	$ 40,734,330	
	Schedule 4 Variance	$ 36,943,851	$ 24,479,002	$ (12,464,849)	$ 14,618,271	$ 8,341,719	$ (6,276,552)	$ 12,764,694	$ 7,913,608	$ (4,851,086)	$ 64,326,816	$ 40,734,330	$ (23,592,486)
	PURCHASED POWER OVER BENCHMARK	$ 1,330,977	$ 143,452	$ (1,187,525)	$ 274,930	$ 782	$ (274,148)	$ 882,030	$ 129,207	$ (752,823)	$ 2,487,937	$ 273,441	$ (2,214,496)

AES INDIANA
Comparison of Actual and Estimated Cost of Fuel

EV if offsetting some really high $ per MWH purchases
MISO price $49 per MWH

MISO price $52 per MWH

Line No.	Description	FAC 136 February-22 Actual	FAC 136 Non Outage Actuals	FAC 136 Eagle Valley Impact	FAC 136 March-22 Actual	FAC 136 Non Outage Actuals	FAC 136 Eagle Valley Impact	FAC 136 TOTAL Actual	FAC 136 Non Outage Actuals	FAC 136 Eagle Valley Impact
	Fuel Cost									
15	Coal and Oil Generation	19,537,889	19,537,889	-	19,250,722	19,250,722	-	38,788,611	38,788,611	-
16	Nuclear Generation	-	-	-	-	-	-	-	-	-
17	Hydro Generation	-	-	-	-	-	-	-	-	-
18	Other Generation - Internal Combustion	2,481	2,481	-	1,584	1,584	-	4,065	4,065	-
19	Natural Gas Generation	15,018,577	28,730,127	13,711,550	14,155,764	19,790,548	5,634,784	29,174,341	48,520,675	19,346,334
	Financial Hedges Gains/Losses & Transactional F	-	-	-	-	-	-	-	-	-
	Purchases through MISO									
20	Wind Purchase Power Agreement Purchases	7,768,052	7,768,052	-	7,126,150	7,126,150	-	14,894,202	14,894,202	-
21	Non-Wind PPA Market Purchases	8,842,750	366,513	(8,476,237)	5,832,660	1,015,789	(4,816,871)	14,675,410	1,382,302	(13,293,108)
22	Other	5,829	5,829	-	7,996	7,996	-	13,825	13,825	-
23	MISO Components of Cost of Fuel	(2,646,879)	(2,646,879)	-	(1,017,652)	(1,017,652)	-	(3,664,531)	(3,664,531)	-
24	Purchased Power other than MISO	1,287,151	1,287,151	-	1,903,496	1,903,496	-	3,190,647	3,190,647	-
	LESS:									
25	Inter-System Sales through MISO	555,647	8,846,000	8,290,353	4,207,976	6,519,866	2,311,890	4,763,623	15,365,866	10,602,243
28	Transmission Losses	95,211	446,397	351,186	295,701	477,268	181,567	390,912	923,665	532,753
29	Lakefield PPA Adjustment	81,563	651,838	570,275	231,919	378,639	146,720	313,482	1,030,477	716,995
30	Purchased Power in Excess	-	-	-	-	-	-	-	-	-
		$ -								
31	Total Fuel Costs (F)	$ 49,083,429	$ 45,106,929	$ (3,976,500)	$ 42,525,124	$ 40,702,859	$ (1,822,265)	$ 91,608,553	$ 85,809,787	$ (5,798,766)
32	F / S (Mills/kWh)	43.933	40.373	-8%	41.158	39.394	-4%	42.600	39.903	
	SCHEDULE 4									
	BILLED SALES	1,233,637	1,233,637		1,110,174	1,110,174		2,343,811	2,343,811	
	ACTUAL COST OF FUEL INCURRED	$ 54,197,375	$ 49,805,627		$ 45,692,541	$ 43,734,195		$ 99,889,917	$ 93,539,821	
	COST OF FUEL IN BASE RATES	$ 40,633,536	$ 40,633,536		$ 36,566,911	$ 36,566,911		$ 77,200,447	$ 77,200,447	
	INCREMENTAL COST OF FUEL	$ 13,563,840	$ 9,172,091		$ 9,125,630	$ 7,167,283		$ 22,689,470	$ 16,339,374	
								$ -	$ -	
	COST OF FUEL BILLED	$ 2,075,079	$ 2,075,079		$ 8,236,202	$ 8,236,202		$ 10,311,281	$ 10,311,281	
		$ 11,488,761	$ 7,097,012		$ 889,428	$ (1,068,919)		$ 12,378,189	$ 6,028,093	
	Schedule 4 Variance	$ 11,488,761	$ 7,097,012	$ (4,391,749)	$ 889,428	$ (1,068,919)	$ (1,958,347)	$ 12,378,189	$ 6,028,093	$ (6,350,096)
	PURCHASED POWER OVER BENCHMARK	$ 257,470	$ 24,832	$ (232,638)	$ 224,712	$ 163,994	$ (60,718)	$ 482,182	$ 188,826	$ (293,356)

AES Indiana
Cause No. 38703 FAC 136
Attachment DJ-7

Evaluation Of Settled Natural Gas Hedge Versus Considered Peak Power Hedge For February 2022

Result of Gas Hedge Transacted	1-Feb	2-Feb	3-Feb	4-Feb	5-Feb	6-Feb	7-Feb	8-Feb	9-Feb	10-Feb	11-Feb	12-Feb	13-Feb	14-Feb
TGT Index Settle	$5.040	$5.210	$6.055	$5.510	$5.145	$5.145	$5.145	$4.080	$4.080	$3.785	$3.655	$3.700	$3.700	$3.700
Hedged Gas Price	$3.842	$3.842	$3.842	$3.842	$3.842	$3.842	$3.842	$3.842	$3.842	$3.842	$3.842	$3.842	$3.842	$3.842
Burned MMBtu	70,000	70,000	70,000	70,000	70,000	70,000	70,000	40,000	40,000	40,000	40,000			
Turnback MMBtu								30,000	30,000	30,000	30,000	70,000	70,000	70,000
Market Settle Value	$83,860.00	$95,760.00	$154,910.00	$116,760.00	$91,210.00	$91,210.00	$91,210.00	$16,660.00	$16,660.00	($3,990.00)	($13,090.00)	($9,940.00)	($9,940.00)	($9,940.00)

Result of Gas Hedge Transacted	15-Feb	16-Feb	17-Feb	18-Feb	19-Feb	20-Feb	21-Feb	22-Feb	23-Feb	24-Feb	25-Feb	26-Feb	27-Feb	28-Feb	Total
TGT Index Settle	$3.865	$3.940	$4.255	$4.425	$4.275	$4.275	$4.275	$4.275	$4.300	$4.460	$4.670	$4.340	$4.340	$4.340	$4.428
Hedged Gas Price	$3.842	$3.842	$3.842	$3.842	$3.842	$3.842	$3.842	$3.842	$3.842	$3.842	$3.842	$3.842	$3.842	$3.842	$3.842
Burned MMBtu	70,000	70,000	40,000	70,000	40,000	40,000	40,000	40,000			70,000				1,130,000
Turnback MMBtu			30,000		30,000	30,000	30,000	30,000	70,000	70,000		70,000	70,000	70,000	830,000
Market Settle Value	$1,610.00	$6,860.00	$28,910.00	$40,810.00	$30,310.00	$30,310.00	$30,310.00	$30,310.00	$32,060.00	$43,260.00	$57,960.00	$34,860.00	$34,860.00	$34,860.00	$1,148,630.00

Financial Power Hedge Considered	1-Feb	2-Feb	3-Feb	4-Feb	5-Feb	6-Feb	7-Feb	8-Feb	9-Feb	10-Feb	11-Feb	12-Feb	13-Feb	14-Feb
257 MWh Peak	4,112	4,112	4,112	4,112			4,112	4,112	4,112	4,112	4,112			4,112
Hedged Price	$63.00	$63.00	$63.00	$63.00			$63.00	$63.00	$63.00	$63.00	$63.00			$63.00
Indiana Hub Peak	$59.68	$61.56	$84.61	$66.49			$67.31	$60.72	$45.28	$47.14	$35.40			$59.55
Value / MWh	($3.32)	($1.44)	$21.61	$3.49	$0.00	$0.00	$4.31	($2.28)	($17.72)	($15.86)	($27.60)	$0.00	$0.00	($3.45)
Market Settle Value	($13,651.84)	($5,921.28)	$88,860.32	$14,350.88	$0.00	$0.00	$17,722.72	($9,375.36)	($72,864.64)	($65,216.32)	($113,491.20)	$0.00	$0.00	($14,186.40)

Financial Power Hedge Considered	15-Feb	16-Feb	17-Feb	18-Feb	19-Feb	20-Feb	21-Feb	22-Feb	23-Feb	24-Feb	25-Feb	26-Feb	27-Feb	28-Feb	Total
257 MWh Peak	4,112	4,112	4,112	4,112			4,112	4,112	4,112	4,112	4,112			4,112	82,240
Hedged Price	$63.00	$63.00	$63.00	$63.00			$63.00	$63.00	$63.00	$63.00	$63.00			$63.00	$63.00
Indiana Hub Peak	$44.96	$35.87	$39.39	$49.91			$42.12	$42.72	$54.82	$61.35	$62.13			$58.15	$53.96
Value / MWh	($18.04)	($27.13)	($23.61)	($13.09)	$0.00	$0.00	($20.88)	($20.28)	($8.18)	($1.65)	($0.87)	$0.00	$0.00	($4.85)	($6.46)
Market Settle Value	($74,180.48)	($111,558.56)	($97,084.32)	($53,826.08)	$0.00	$0.00	($85,858.56)	($83,391.36)	($33,636.16)	($6,784.80)	($3,577.44)	$0.00	$0.00	($19,943.20)	($743,614.08)

Total value of the natural gas hedge	$1,148,630.00
Potential value of the peak power hedge	($743,614.08)
Net Difference	$1,892,244.08

Using natural gas hedges instead of power hedges created a benefit for the customer of $1,892,244

Indianapolis Power & Light Company
Cause No. 38703 FAC 136
Attachment DJ-8

Physical Hedge Saving and Cost Daily Valuation: ($3,876,875)

Transaction 1		REX/GDD	Hedge/GDD	Hedge
Volume	**Price**	**Index Price**	**Difference**	**Savings or Cost**
25,000	$ 6.7700	$ 5.0800	$ (1.6900)	$ (42,250.00)
25,000	$ 6.7700	$ 5.3600	$ (1.4100)	$ (35,250.00)
25,000	$ 6.7700	$ 6.3850	$ (0.3850)	$ (9,625.00)
25,000	$ 6.7700	$ 5.4100	$ (1.3600)	$ (34,000.00)
25,000	$ 6.7700	$ 5.0200	$ (1.7500)	$ (43,750.00)
25,000	$ 6.7700	$ 5.0200	$ (1.7500)	$ (43,750.00)
25,000	$ 6.7700	$ 5.0200	$ (1.7500)	$ (43,750.00)
25,000	$ 6.7700	$ 4.0350	$ (2.7350)	$ (68,375.00)
25,000	$ 6.7700	$ 4.0450	$ (2.7250)	$ (68,125.00)
25,000	$ 6.7700	$ 3.7500	$ (3.0200)	$ (75,500.00)
25,000	$ 6.7700	$ 3.6300	$ (3.1400)	$ (78,500.00)
25,000	$ 6.7700	$ 3.7200	$ (3.0500)	$ (76,250.00)
25,000	$ 6.7700	$ 3.7200	$ (3.0500)	$ (76,250.00)
25,000	$ 6.7700	$ 3.7200	$ (3.0500)	$ (76,250.00)
25,000	$ 6.7700	$ 3.8250	$ (2.9450)	$ (73,625.00)
25,000	$ 6.7700	$ 3.9450	$ (2.8250)	$ (70,625.00)
25,000	$ 6.7700	$ 4.2550	$ (2.5150)	$ (62,875.00)
25,000	$ 6.7700	$ 4.4050	$ (2.3650)	$ (59,125.00)
25,000	$ 6.7700	$ 4.3500	$ (2.4200)	$ (60,500.00)
25,000	$ 6.7700	$ 4.3500	$ (2.4200)	$ (60,500.00)
25,000	$ 6.7700	$ 4.3500	$ (2.4200)	$ (60,500.00)
25,000	$ 6.7700	$ 4.3500	$ (2.4200)	$ (60,500.00)
25,000	$ 6.7700	$ 4.5000	$ (2.2700)	$ (56,750.00)
25,000	$ 6.7700	$ 4.7850	$ (1.9850)	$ (49,625.00)
25,000	$ 6.7700	$ 4.8550	$ (1.9150)	$ (47,875.00)
25,000	$ 6.7700	$ 4.3250	$ (2.4450)	$ (61,125.00)
25,000	$ 6.7700	$ 4.3250	$ (2.4450)	$ (61,125.00)
25,000	$ 6.7700	$ 4.3250	$ (2.4450)	$ (61,125.00)
			Total	**$ (1,617,500.00)**

Transaction 2		REX/GDD	Hedge/GDD	Hedge
Volume	**Price**	**Index Price**	**Difference**	**Savings or Cost**
25,000	$ 6.3900	$ 5.0800	$ (1.3100)	$ (32,750.00)
25,000	$ 6.3900	$ 5.3600	$ (1.0300)	$ (25,750.00)
25,000	$ 6.3900	$ 6.3850	$ (0.0050)	$ (125.00)
25,000	$ 6.3900	$ 5.4100	$ (0.9800)	$ (24,500.00)
25,000	$ 6.3900	$ 5.0200	$ (1.3700)	$ (34,250.00)
25,000	$ 6.3900	$ 5.0200	$ (1.3700)	$ (34,250.00)
25,000	$ 6.3900	$ 5.0200	$ (1.3700)	$ (34,250.00)
25,000	$ 6.3900	$ 4.0350	$ (2.3550)	$ (58,875.00)
25,000	$ 6.3900	$ 4.0450	$ (2.3450)	$ (58,625.00)
25,000	$ 6.3900	$ 3.7500	$ (2.6400)	$ (66,000.00)
25,000	$ 6.3900	$ 3.6300	$ (2.7600)	$ (69,000.00)
25,000	$ 6.3900	$ 3.7200	$ (2.6700)	$ (66,750.00)
25,000	$ 6.3900	$ 3.7200	$ (2.6700)	$ (66,750.00)
25,000	$ 6.3900	$ 3.7200	$ (2.6700)	$ (66,750.00)
25,000	$ 6.3900	$ 3.8250	$ (2.5650)	$ (64,125.00)
25,000	$ 6.3900	$ 3.9450	$ (2.4450)	$ (61,125.00)
25,000	$ 6.3900	$ 4.2550	$ (2.1350)	$ (53,375.00)
25,000	$ 6.3900	$ 4.4050	$ (1.9850)	$ (49,625.00)
25,000	$ 6.3900	$ 4.3500	$ (2.0400)	$ (51,000.00)
25,000	$ 6.3900	$ 4.3500	$ (2.0400)	$ (51,000.00)
25,000	$ 6.3900	$ 4.3500	$ (2.0400)	$ (51,000.00)
25,000	$ 6.3900	$ 4.3500	$ (2.0400)	$ (51,000.00)
25,000	$ 6.3900	$ 4.5000	$ (1.8900)	$ (47,250.00)
25,000	$ 6.3900	$ 4.7850	$ (1.6050)	$ (40,125.00)
25,000	$ 6.3900	$ 4.8550	$ (1.5350)	$ (38,375.00)
25,000	$ 6.3900	$ 4.3250	$ (2.0650)	$ (51,625.00)
25,000	$ 6.3900	$ 4.3250	$ (2.0650)	$ (51,625.00)
25,000	$ 6.3900	$ 4.3250	$ (2.0650)	$ (51,625.00)
			Total	**$ (1,351,500.00)**

Transaction 3		TGT/GDD	Hedge/GDD	Hedge
Volume	**Price**	**Index Price**	**Difference**	**Savings or Cost**
25,000	$ 5.7250	$ 5.0400	$ (0.6850)	$ (17,125.00)
25,000	$ 5.7250	$ 5.2100	$ (0.5150)	$ (12,875.00)
25,000	$ 5.7250	$ 6.0550	$ 0.3300	$ 8,250.00
25,000	$ 5.7250	$ 5.5100	$ (0.2150)	$ (5,375.00)
25,000	$ 5.7250	$ 5.1450	$ (0.5800)	$ (14,500.00)
25,000	$ 5.7250	$ 5.1450	$ (0.5800)	$ (14,500.00)
25,000	$ 5.7250	$ 5.1450	$ (0.5800)	$ (14,500.00)
25,000	$ 5.7250	$ 4.0800	$ (1.6450)	$ (41,125.00)
25,000	$ 5.7250	$ 4.0800	$ (1.6450)	$ (41,125.00)
25,000	$ 5.7250	$ 3.7850	$ (1.9400)	$ (48,500.00)
25,000	$ 5.7250	$ 3.6550	$ (2.0700)	$ (51,750.00)
25,000	$ 5.7250	$ 3.7000	$ (2.0250)	$ (50,625.00)
25,000	$ 5.7250	$ 3.7000	$ (2.0250)	$ (50,625.00)
25,000	$ 5.7250	$ 3.7000	$ (2.0250)	$ (50,625.00)
25,000	$ 5.7250	$ 3.8650	$ (1.8600)	$ (46,500.00)
25,000	$ 5.7250	$ 3.9400	$ (1.7850)	$ (44,625.00)
25,000	$ 5.7250	$ 4.2550	$ (1.4700)	$ (36,750.00)
25,000	$ 5.7250	$ 4.4250	$ (1.3000)	$ (32,500.00)
25,000	$ 5.7250	$ 4.2750	$ (1.4500)	$ (36,250.00)
25,000	$ 5.7250	$ 4.2750	$ (1.4500)	$ (36,250.00)
25,000	$ 5.7250	$ 4.2750	$ (1.4500)	$ (36,250.00)
25,000	$ 5.7250	$ 4.2750	$ (1.4500)	$ (36,250.00)
25,000	$ 5.7250	$ 4.3000	$ (1.4250)	$ (35,625.00)
25,000	$ 5.7250	$ 4.4600	$ (1.2650)	$ (31,625.00)
25,000	$ 5.7250	$ 4.6700	$ (1.0550)	$ (26,375.00)
25,000	$ 5.7250	$ 4.3400	$ (1.3850)	$ (34,625.00)
25,000	$ 5.7250	$ 4.3400	$ (1.3850)	$ (34,625.00)
25,000	$ 5.7250	$ 4.3400	$ (1.3850)	$ (34,625.00)
			Total	**$ (907,875.00)**

$ (3,876,875.00)

Total $ (3,876,875.00)

Natural Gas Hedge For April 2022

Transaction 1		REX/GDD	Hedge/GDD	Hedge
Volume	**Price**	**Index Price**	**Difference**	**Savings or Cost**
15,000	$ 5.1000	$ 5.3100	$ 0.2100	$ 3,150.00
15,000	$ 5.1000	$ 5.3050	$ 0.2050	$ 3,075.00
15,000	$ 5.1000	$ 5.3050	$ 0.2050	$ 3,075.00
15,000	$ 5.1000	$ 5.3050	$ 0.2050	$ 3,075.00
15,000	$ 5.1000	$ 5.4650	$ 0.3650	$ 5,475.00
15,000	$ 5.1000	$ 5.8150	$ 0.7150	$ 10,725.00
15,000	$ 5.1000	$ 6.1300	$ 1.0300	$ 15,450.00
15,000	$ 5.1000	$ 5.9000	$ 0.8000	$ 12,000.00
15,000	$ 5.1000	$ 5.9800	$ 0.8800	$ 13,200.00
15,000	$ 5.1000	$ 5.9800	$ 0.8800	$ 13,200.00
15,000	$ 5.1000	$ 5.9800	$ 0.8800	$ 13,200.00
15,000	$ 5.1000	$ 6.1500	$ 1.0500	$ 15,750.00
15,000	$ 5.1000	$ 6.2950	$ 1.1950	$ 17,925.00
15,000	$ 5.1000	$ 6.5400	$ 1.4400	$ 21,600.00
15,000	$ 5.1000	$ 6.8150	$ 1.7150	$ 25,725.00
15,000	$ 5.1000	$ 6.8150	$ 1.7150	$ 25,725.00
15,000	$ 5.1000	$ 6.8150	$ 1.7150	$ 25,725.00
15,000	$ 5.1000	$ 6.8150	$ 1.7150	$ 25,725.00
15,000	$ 5.1000	$ 7.5050	$ 2.4050	$ 36,075.00
15,000	$ 5.1000	$ 6.8450	$ 1.7450	$ 26,175.00
15,000	$ 5.1000	$ 6.5950	$ 1.4950	$ 22,425.00
15,000	$ 5.1000	$ 6.4950	$ 1.3950	$ 20,925.00
15,000	$ 5.1000	$ 6.2050	$ 1.1050	$ 16,575.00
15,000	$ 5.1000	$ 6.2050	$ 1.1050	$ 16,575.00
15,000	$ 5.1000	$ 6.2050	$ 1.1050	$ 16,575.00
15,000	$ 5.1000	$ 6.4200	$ 1.3200	$ 19,800.00
15,000	$ 5.1000	$ 6.7550	$ 1.6550	$ 24,825.00
15,000	$ 5.1000	$ 6.8850	$ 1.7850	$ 26,775.00
15,000	$ 5.1000	$ 6.5250	$ 1.4250	$ 21,375.00
15,000	$ 5.1000	$ 6.5250	$ 1.4250	$ 21,375.00
			Total	**$ 523,275.00**

Total $ 523,275.00

CONFIDENTIAL ATTACHMENT DJ-10

[CONFIDENTIAL – NOT REPRODUCED HEREIN]

CONFIDENTIAL ATTACHMENT DJ-11

[CONFIDENTIAL – NOT REPRODUCED HEREIN]