OFFICIAL EXHIBITS

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INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

IURC
PETITIONER'S
EXHIBIT NO. 2
11-12-21 AT
DATE REPORTER

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 DECEMBER 2021 THROUGH FEBRUARY 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 APPROVAL OF A FUEL HEDGING PLAN AND AUTHORITY TO RECOVER COSTS OF THE FUEL HEDGING PLAN PURSUANT TO I.C. 8-1-2-42.	)	**CAUSE NO. 38703 FAC 133**

APPLICANT'S SUBMISSION OF DIRECT TESTIMONY OF
<u>DAVID JACKSON</u>

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,

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D/B/A AES INDIANA

CERTIFICATE OF SERVICE

The undersigned hereby certifies that a copy of the foregoing was served this 17th day of September, 2021, by email transmission, hand delivery or United States Mail, first class, postage prepaid to:

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ATTORNEYS FOR APPLICANT
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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", or the "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 2021 projected coal burn and coal purchases and on how AES Indiana proposes to address its coal inventory if it reaches maximum onsite storage levels.
- The results of AES Indiana's natural gas hedging plan for the Eagle Valley Combined Cycle Gas Turbine ("CCGT").
- The Eagle Valley CCGT forced outage and how AES Indiana has acted to mitigate the price risk of the outage by completing financial peak power hedges.

- Update and request for approval of AES Indiana's hedging policy covering coal and natural gas.
- Finally, in FAC 127, I testified that the 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.

Q7. Are you sponsoring any attachments?

A7. Yes. I am sponsoring the following attachments:

- <u>Attachment DJ-1</u> – Calculation of daily benchmarks.
- <u>Attachment DJ-2</u> – 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.
- <u>Confidential Attachment DJ-3</u> – Commitment summary and weekly model runs used in Petersburg commitment decisions May 2021 through July 2021.
- <u>Confidential Attachment DJ-4</u> – 2021 Petersburg Coal Position and provides a monthly view of 2021 purchases, burns, and inventory.
- <u>Confidential Attachment DJ-5</u> – AES Indiana proposed Fuel Hedging Policy.
- <u>Confidential Attachment DJ-6</u> – AES Indiana proposed natural gas purchase table supporting the Fuel Hedging Policy document.

Q8. Were <u>Attachments DJ-1 and DJ-2</u> and <u>Confidential Attachments DJ-3 and DJ-4</u> prepared or assembled by you or under your direction and supervision?

A8. Yes.

Q9. Are you submitting any workpapers?

A9. Yes. I am submitting the following workpapers which were prepared or assembled by me or under my direction and supervision:

- Workpaper DJ-1, which provides detailed calculations of the cost associated with the peak power hedges.
- Confidential Workpaper DJ-2, which supports Table DJ-2.
- Workpaper DJ-3 which illustrates the amount of purchased power over the benchmark related to the outage at Eagle Valley.
- Workpaper DJ-4 EV Fuel Variances for FAC 133 which illustrates actual fuel costs offset by peak power hedges, FAC forecast fuel costs, and estimated actual fuel costs had Eagle Valley CCGT been in service.

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 proposed recovery of costs for December 2021 through February 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 December 2021 through February 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 is reflecting a reconciliation of these fuel-related MISO costs and revenues for the historical period of May 2021 through July 2021. 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 December 2021 through February 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.

Q18. 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?

A18. 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.

Q19. 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?

A19. 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.

Q20. Please discuss AES Indiana's experience with MISO's Ancillary Services Market ("ASM").

A20. 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. Day Ahead and Real Time market clearing prices for Regulation, Spinning and Supplemental Reserves appear to be at reasonable levels consistent with market conditions. For the period of May 2021 through July 2021, the average ASM prices per megawatt hour were as follows:

Month	Regulation	Spinning	Supplemental
May 2021	$0.0524	$0.0524	$0.0051
June 2021	$0.0484	$0.0551	$0.0287
July 2021	$0.0491	$0.0585	$0.0190

Q21. Is AES Indiana requesting recovery of Revenue Sufficiency Guarantee ("RSG") Payments in this FAC proceeding?

A21. Yes.

Q22. Have you reviewed the Commission's June 3, 2009 Order in Cause No. 43664 (the "RSG Order")?

A22. Yes.

Q23. Is AES Indiana's request for recovery of RSG Payments consistent with your understanding of the Commission's RSG Order?

A23. Yes.

Q24. Are you familiar with the term "Contestable RT RSG Charges"?

A24. 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.

Q25. What are the RSG Daily Benchmarks for the period of May 2021 through July 2021?

A25. 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.

Q26. How does AES Indiana recover the cost of power purchased in the MISO markets?

A26. 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.

Q27. What are the Purchased Power Daily Benchmarks for May 2021 through July 2021?

A27. 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.

Q28. Is AES Indiana seeking to recover any purchased power costs incurred in May 2021 through July 2021 that are in excess of the Daily Benchmarks calculated pursuant to the Purchased Power Order?

A28. Yes. AES Indiana incurred a total of $1,198,183 of purchased power costs over the applicable Purchased Power Daily Benchmarks during May 2021 through July 2021. 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. Utilizing the methodology approved in the Purchased Power Order, $0 of the purchased power is non-recoverable during this accounting period. Therefore, AES Indiana is seeking to recover $1,198,183 of purchased power costs in excess of the applicable Purchased Power Daily Benchmarks for May 2021 through July 2021.

Q29. What were the primary drivers of the purchased power costs above the benchmark during the historical FAC period?

A29. The majority of the purchased power over benchmark occurred in three periods when baseload generation was unavailable. May 22 through May 27 accounted for $581,794. During the period Petersburg Unit 4 was in planned outage, Petersburg Unit 2 came off line due to a tube leak, Eagle Valley was in forced outage, and Harding Street Unit 7 became unavailable due to a boiler feed pump issue. The May 22 through May 27 period also experienced the first hot temperatures of the season, with temperatures in the mid to upper 80's. June 8 through June 12 accounted for $293,853 of the total purchased power over the benchmark. During this period Petersburg Unit 2 and 3 came off line due to tube leaks, Eagle Valley was in forced outage, and Harding Street Unit 7 was unavailable due to a boiler feed pump issue. Additionally, the MISO northern region experienced high temperatures and high power demand leading to periods of high priced power. July 2 though July 6 accounted for $139,401. During the period Eagle Valley was in forced outage, Petersburg Unit 3 came offline due to repair a internal scrubber leak, and Petersburg Unit 2 came offline due to a tube leak. The end of the period experienced high temperatures in the upper 80's and higher priced power associated with high loads in MISO.

Q30. Do you believe the total purchased power costs incurred in May 2021 through July 2021 are reasonable?

A30. Yes.

FUEL PURCHASES

Q31. Are you familiar with AES Indiana's purchases of fuel for use in its generating stations?

A31. 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.

Q32. Are purchases for natural gas included in this FAC?

A32. 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.

Q33. How does AES Indiana make fuel oil purchases?

A33. 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.

Q34. How does AES Indiana purchase its coal supply?

A34. AES Indiana normally purchases all of its coal from the Illinois Basin, primarily from Indiana producers. We currently have contracts with four coal producers and receive coal from up to six different mines.

Q35. With what coal companies does AES Indiana presently have contracts?

A35. Peabody Energy Corporation, Sunrise Coal, LLC, Gibson County Coal Company, and White Stallion Energy, LLC.

Q36. Does AES Indiana have any ownership interest in any of these companies?

A36. No.

Q37. Why does AES Indiana engage in spot purchases of coal?

A37. We use spot purchases of coal in three ways: (1) 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.

Q38. What procedure does AES Indiana follow in negotiating long-term coal contracts?

A38. 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.

Q39. Why does AES Indiana normally purchase substantially all of its coal from Indiana providers?

A39. 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.

Q40. 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?

A40. 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.

Q41. What does AES Indiana do to verify the reasonableness of its coal costs?

A41. 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

Q42. Are any purchases from the Hoosier Wind Park and/or Lakefield Wind Park included in this FAC, either in projected or actual fuel costs?

A42. 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 May 2021, June 2021, and July 2021, AES Indiana received 12,586 MWhs, 12,379 MWhs, and 8,716 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 May 2021, June 2021, and July 2021, AES Indiana received 23,895 MWhs, 23,463 MWhs, and 18,455 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.

Q43. Where are these wind purchases shown in AES Indiana's schedules in this proceeding?

A43. 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.

Q44. Please provide an update regarding the Locational Marginal Prices ("LMPs") at the Lakefield Wind Park and the Hoosier Wind Park.

A44. 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 lower than the level of curtailments experienced during the time period covered by FAC 132, and slightly higher than the time period experienced one year ago (FAC 129). The higher volume of curtailments was associated with periods of negative LMP pricing that occurred May 2021 through July 2021. There were no MWhs of 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

Q45. Please provide an overview of the AES Indiana's unit commitment process.

A45. 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.

Q46. Please explain what you mean by *predicted* economic performance of the unit and "realized day ahead pricing".

A46. 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.

Q47. What is your understanding of how prudence is assessed?

A47. 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.

Q48. Did the Company act prudently with respect to the commitment and operation of Petersburg during May 2021 through July 2021?

A48. 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.

Q49. Is it reasonable to rely solely on pricing to decide whether and how to commit AES Indiana's generating units?

A49. 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 on line, the potential to have difficulty bringing units back after long outage periods, and the potential for other MISO resources to have operational issues, create significant price risk for AES Indiana's customers.

Q50. 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 May 2021 through July 2021?

A50. Yes. The actual fuel costs were higher than forecast, resulting in a weighted average deviation of -13.22%. The May 2021, June 2021, and July 2021 deviations of actual to forecast F/S were -9.47%, -14.00%, and -15.39%, respectively. The two largest drivers of the variance are the increase in natural gas prices and the Eagle Valley CCGT forced outage. NYMEX natural gas prices increased from \$2.86/MMBtu on May 3rd to \$4.02/MMBtu on July 30th. The increase in natural gas price impacted generation costs at Harding Street and Georgetown units and elevated market prices of purchase power. The forced outage of the Eagle Valley CCGT, which was expected to be operational in the forecast for each of the months reconciled in this FAC 133 filing, increased the volume of purchased power covered in the marketplace versus baseload values from expected generation. The May 2021, June 2021, and July 2021 Indianapolis temperature variance from normal was -2.7 degrees, +1.6 degrees, and -0.9 degrees, respectively.

Q51. Can you provide more detail regarding the natural gas price increase during the May 2021 through July 2021 period?

A51. Yes. As stated in Q&A 50, NYMEX natural gas prices increased from $2.86/MMBtu on May 3, 2021 to $4.02/MMBtu on July 30, 2021. The key drivers of the price increase were strong demand from the power generation sector due to record heat, especially in the western United States, liquified natural gas export demand, static natural gas production, and concern over the slow pace of natural gas injections to build inventory for the coming winter.

Q52. Please summarize the status of the Petersburg Units during the May 2021 through July 2021 historical time period.

A52. Petersburg Units 1, 2, and 3 were in must run status early in the historical FAC period at the request of Transmission Operations Control Center ("TOCC") for system reliability. Petersburg Unit 4 was in planned outage entering the period until the end of May. Petersburg Unit 1 retired on May 31, 2021. During the balance of the historical FAC period, Petersburg Unit 2, 3, and 4 were offered as economic except when the units were in outage or returning from outage.

Q53. Please summarize the commitment status of each of the Petersburg units during the May 2021 through July 2021 time period.

A53. 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.

Table DJ-1 – Pete Commitment Status

Commitment Status During FAC 133 Historical Period

	Pete 1	Pete 2	Pete 3	Pete 4
Must Run	77%	25%	37%	1%
Economic	23%	43%	48%	59%
Emergency	0%	0%	0%	0%
Outage	0%	32%	15%	40%

The majority of the must run commitment occurred in May and early June 2021 due the request by TOCC to run Petersburg Units 1, 2, and 3 for system reliability. Additionally, must run status may be driven by operational needs or economics when units have short periods of marginal or negative value but the modeled weekly values are positive. Commitment decisions are discussed in more detail in Q/A 56 and Confidential Attachment DJ-3.

Q54. Did you document the forward pricing reflected in the unit commitment decisions for the months of May 2021 through July 2021?

A54. 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-3 provides a summary and the model runs used for commitment decisions during each week of the May 2021 through July 2021 period.

Q55. In your opinion, was AES Indiana's operation of the Petersburg units during May 2021 through July 2021 reasonably aligned with market prices?

A55. Yes. During the historical FAC period all of the weekly 7-day model runs showed positive margin for Petersburg Units 1, 2, 3, and 4, except the 7-day period beginning May 29, 2021 for Petersburg Unit 1. During that period, Petersburg Unit 1 showed small negative value for the remaining 3 days before the unit was retired, but was must run at the request of TOCC for system relaibilty.

Petersburg Unit 2 was a must run offer the first 2 weekends due to expected marginal weekend pricing but showed positive value for the corresponding modeled 7-day periods. Beginning May 12, 2021, Petersburg Unit 2 was offered as must run at the request of TOCC for system reliability, which remained in place through June 8, 2021. The balance of the historical FAC period the unit was offered as economic when available.

Petersburg Unit 3 was a must run offer the first 2 weekends due to expected marginal weekend pricing but showed positive value for the corresponding modeled 7-day periods. Beginning May 12, 2021, Petersburg Unit 3 was offered as must run at the request of TOCC for system reliability, which remained in place through June 8, 2021. The balance of the histrocial FAC period the unit was offered as economic when available, except July 9, 2021, when the unit was offered as must run while in start up returning from a forced outage.

Petersburg Unit 4 enterd the historical FAC period in planned outage which lasted through May 28, 2021. The balance of the historical FAC period the unit was offered as economic when available, except July 21, 2021, when the unit was offered as must run while in start up returning from a forced outage.

Q56. Please provide further detail on the unit commitment decisions in the May 2021 through July 2021 time period.

A56. 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-3. 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 1

Petersburg Unit 1 ("Unit 1") entered the start of the historical FAC period online and offered as must run. Unit 1 was offered as must run the first two weekends of May due to marginal pricing over the weekend but positive economic value for the balance of each of the first two weeks of May. May 12 through May 31, Unit 1 was offered as must run at the request of TOCC for system reliability. Unit 1 was retired May 31, 2021.

Petersburg Unit 2

Petersburg Unit 2 ("Unit 2") entered the start of the historical FAC period online and offered as must run. Unit 2 was offered as must run the first two weekends of May due to marginal pricing over the weekend but positive economic value for the balance of each of the first two weeks of May. May 12 through May 22, Unit 2 was offered as must run at the request of TOCC for system reliability. Unit 2 came offline May 22 due to a tube leak and remained in outage through May 31. Upon return from outage, Unit 2 was offered as must run for system reliability through June 8 when the unit came offline due to a tube leak. Unit 2 returned to service June 15 and was online and offered to MISO as economic through July 6, when the unit came offline due to a tube leak. Unit 2 returned to service July 14 and was online and offered to MISO as economic through July 27. Unit 2 came offline July 28 for a tube leak and remained in outage for the balance 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 must run. Unit 3 was offered as must run the first 2 weekends of May due to marginal pricing over the weekend but positive economic value for the balance of each of the first two weeks of May. For May 12 through June 8, Unit 3 was online and offered as must run at the request of TOCC for system reliability. Unit 3 was released from must run by TOCC June 8 and was offered as economic to MISO until the unit came offline on June 11 due to a tube leak. Unit returned to service on June 19 and remained online and offered to MISO as economic through July 2. Unit 3 came offline July 2 for an internal scrubber leak repair and remained in outage through July 8. Unit 3 was offered as must run on July 9 while in startup. July 10, Unit 3 was switched to an economic offer in MISO and remained online offered as econimc for the balance of the historical FAC period.

Petersburg Unit 4

Petersburg Unit 4 ("Unit 4") entered the historical FAC period offline in a planned maintenance outage. The maintenance outage was completed May 28 and the unit was offered as economic to MISO while in start up. Unit 4 experienced a grounded generator excitor during start up on June 1 and was placed in outage to complete repairs. Unit 4 began startup and was online June 7. The unit remained online and offered to MISO as economic through July 17 when the unit was forced offline for a tube leak repair. Unit 4 remained in outage through July 20 and was offered as must run while in startup July 21.Unit 4 was offered as economic and online for the balance of the historical FAC period.

Q57. Has AES Indiana performed a look back analysis to assess the economics of the Petersburg Station unit commitments for May 2021 through July 2021?

A57. 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.

Q58. Why did you perform the look back analysis?

A58. 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.

Q59. Please discuss the look back analysis for May 2021 through July 2021.

A59. AES Indiana performed an evaluation of Petersburg for May 2021 through July 2021 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 customer.

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 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-2[1]
Petersburg Margin Look Back Analysis

	Pete 1	Pete 2	Pete 3	Pete 4	All Units
May	$ 1,084,656	$ 605,738	$ 2,432,232	$ -	$ 4,122,626
June	$ -	$ 2,080,399	$ 3,047,508	$ 3,889,865	$ 9,017,771
July	$ -	$ 3,126,129	$ 4,164,407	$ 5,240,197	$ 12,530,733
Total	$ 1,084,656	$ 5,812,266	$ 9,644,147	$ 9,130,061	$ 25,671,130

Additionally, during the May 2021 through July 2021 period off-system sales margin was $307,511 all of which (100%) goes to the customer.

[1] Supporting detail for this table is included in Confidential Workpaper DJ-2.

Q60. 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.

A60. 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 December 2021 through February 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, 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 (May 2021 through July 2021) is shown in <u>Confidential Attachment DJ-3</u>.

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

Q61. Please update the Commission on AES Indiana's 2021 projected coal burn and coal purchases.

A61. Confidential Attachment DJ-4 shows the realized and projected monthly purchases and burns for 2021. The Company purchased coal for 2022 in July and has issued an RFP and plans to make additional purchases in September 2021 to meet hedge targets through 2024. Burns for summer have remained strong and current inventory is within the target range. AES Indiana will continue to closely monitor projected coal burns and purchases. AES Indiana plans to discuss this subject in further detail with the OUCC during its FAC 133 audit.

Q62. Is AES Indiana's coal inventory within its target levels?

A62. Yes. AES Indiana inventory is currently within our 25-50 day supply of coal inventory target range.

Q63. What is AES Indiana doing to manage its inventory level?

A63. 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.

Q64. Coal decrement pricing was discussed as an option to manage coal inventory in FAC 128. Did AES Indiana use decrement pricing during the FAC 133 historical period?

A64. No. AES Indiana did not use decrement pricing during the FAC 133 historical period of May 2021 through July 2021.

Q65. What are AES Indiana's current expectations regarding the use of decrement pricing?

A65. With current coal inventory levels inside of the target range and the current forecasted 2021 coal position, AES Indiana does not see any risk of decremental burn in 2021.

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

A66. No. There is no decrement pricing in the forecast period of December 2021 through February 2022.

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

A67. No.

EAGLE VALLEY CCGT OUTAGE

Q68. Please provide background on the Eagle Valley CCGT outage.

A68. Eagle Valley CCGT had a planned annual maintenance outage from April 10 through April 24. As discussed by AES Indiana witness Bigalbal, when the unit returned from outage and began start up, it experienced issues with the breakers and relays that prohibited the unit from synchronizing with the grid. In the review of the event, it was determined there was a ground fault in the field of the steam turbine generator. Further investigation revealed damage to the generator's rotor and copper bars, as well as cleanup and re-wedging of the stator.

Q69. What is the expected duration of the Eagle Valley forced outage?

A69. As discussed by AES Indiana Witness Bigalbal, Eagle Valley CCGT is expected to be in outage until November 7, 2021.

Q70. What is the status of the Root Cause Analysis ("RCA") status of the Eagle Valley CCGT forced outage?

A70. The RCA is completed and is being filed with the FAC 133 testimony provided by AES Indiana Witness Bigalbal.

Q71. Does the Eagle Valley CCGT forced outage impact deliverable power to AES Indiana customers during the remaining outage period?

A71. No. The AES Indiana transmission system has sufficient import capabilities to serve AES Indiana customers without Eagle Valley operating. AES Indiana anticipates having available 2,261 MWs of generation supply towards the expected September peak load of 2,409 MWs. This leaves a reliance on imports from the MISO market for approximately 148 MWs during the peak hour of load. During October, AES Indiana anticipates having available 2,091 MWs of generation supply towards the expected October peak load of 1,676 MWs. In the event of a short position, as a member of MISO, which maintains generation capacity, operating reserves, and load modifying resources to meet system demand, AES Indiana has access to economic power available for import into our distribution system.

Q72. What is the impact of the forced outage on the purchased power above the benchmark for FAC 133?

A72. Eagle Valley CCGT was in forced outage for the entire FAC 133 historical period of May 2021 through July 2021. The Company incurred purchased power costs over the benchmarkof $1,198,183 during the FAC 133 historical period. The portion of purchased power above the benchmark that could be attributable to the Eagle Valley outage was $1,108,511 (see Workpaper DJ-3 included in this filing).

Q73. Has AES Indiana completed additional analysis outlining the impact of the Eagle Valley CCGT forced outage?

A73. The Company compared the cost of natural gas generation and purchased power through MISO in three scenarios: 1) actual cost with the benefit of the peak power hedges, 2) FAC 133 forecast cost, and 3) estimated actual fuel cost if the Eagle Valley CCGT had been operational (determined by means of a back cast using realized hourly LMPs and natural gas prices). This analysis did not look at any other potential impacts to the FAC.

When compared to the FAC 133 forecast cost, the comparison shows that, due to rising natural gas prices, had Eagle Valley CCGT been operational, natural gas fuel cost would have been significantly higher than forecast and purchase power through MISO would have been significantly lower than forecast. The analysis shows that the actual fuel cost with the benefit of peak power hedges is $705,826 less than what the actual fuel cost would have been if Eagle Valley CCGT had been operational during the period. This analysis is presented in my Workpaper DJ-4 EV Fuel Variances.

Q74. What is the impact of the forced outage in the forecast period of FAC 133?

A74. There is no impact to the forecast period. Eagle Valley is expected to be available during the entire FAC 133 forecast period of December 2021 through February 2022.

Q75. Has AES Indiana taken steps to mitigate the power price risk of the Eagle Valley CCGT forced outage for AES Indiana customers?

A75. 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. AES Indiana is providing support for the hedge decision, execution, and financial results of the hedges realized in June and July of 2021 in FAC 133. The same support will be provided for the August and September of 2021 hedges in FAC 134.

EAGLE VALLEY CCGT FINANCIAL POWER HEDGES

Q76. Did AES Indiana engage in peak power transactions as a result of the Eagle Valley CCGT outage?

A76. Yes. On May 27, 2021, AES Indiana purchased MISO day ahead Indiana hub peak power for June, July, and August. The June peak power hedges were 345 MW (121,440 MWh total for the month) at a purchase price of $34.40 per MWh. The July and August peak power hedges were 365 MW (251,120 MWh total for the 2 month period) at a purchase price of $39.15/MWh. On June 18, 2021, AES Indiana purchased MISO day ahead Indiana hub peak power for September. The September peak power hedges 440 MW's (147,840 MWh total for the month) at a purchase price of $40.10 per MWh.

Q77. What was the process that AES Indiana used to determine the appropriate volume of the power hedges?

A77. AES Indiana used a multi-step analysis to determine the appropriate volume of power hedges designed to determine the appropriate hedge size to reduce net market exposure during June-August 2021 and return customers to the risk level they experienced absent the outage. The steps can be summarized as follows:

<u>Step 1. Run production cost model to produce 200 simulated scenarios of monthly generation net margin and cost of serving load</u>. AES Indiana used its production cost model to produce 200 stochastic scenarios of monthly generation and load related metrics for the months of June 2021 through August 2021. For each scenario, the model produced metrics covering non-Eagle Valley generation output and net margin, Eagle Valley output and net margin, Indiana Hub LMPs, AES Indiana load, and cost to serve Indiana AES load.

<u>Step 2. Determine the historical relationship between energy prices (i.e., LMPs) and load volume</u>. Using historical (i.e., January 2014 – December 2020) monthly average Indiana Hub LMPs and MISO LRZ 6 average load, we developed regressions that predicted how unexpected variations in energy prices might translate into variations in average load levels.

<u>Step 3. Revise the scenario-specific cost of serving load outcomes found in Step 1 to reflect the historical relationships identified in Step 2</u>. The production cost model output included 200 scenarios of monthly average Indiana Hub LMPs for each month, along with the mean and standard deviation of AES Indiana load for each month. Using this data as an input into the regression formulae developed in Step 2, we simulated the AES Indiana load levels and cost to serve we might expect given the energy price level in each scenario. We simulated five separate load levels for each of the original 200 scenarios, resulting in a total of 1000 re-simulated scenarios.

Step 4. Determine the base case portfolio net cost risk exposure, assuming the continued operation of Eagle Valley. The base case portfolio net cost is equal to the gross cost of serving load less net margin produced by generation resources. With Eagle Valley included, we calculated the portfolio net cost risk exposure as the difference between the 95th percentile and mean values.

Step 5. Determine the smallest hedge volume that returns AES customers to their original risk exposure. We calculate the hedge offset for hedge sizes ranging from 1% to 200% of Eagle Valley's average net output. The hedge offset is calculated as the hedge sale price (at the current market forward at the time of the model run) less the simulated spot price outcome, multiplied by the hedge volume. For each of the potential hedge volumes, we calculated the hedged portfolio net cost risk exposure and identified which hedge volume reduced the risk exposure down to the level identified in Step 4.

Q78. Was the power hedge reasonable based on the facts and circumstances as they existed at the time the transaction was entered?

A78. Yes. The loss of Eagle Valley CCGT exposed AES Indiana customers to price risk in the summer time period when higher temperatures can create periods of high priced peak power. The peak power purchases were transacted with a single counterparty for the full target volume to eliminate market price risk associated with liquidity. Pricing was confirmed using power broker prices and visible markets on the ICE.

Q79. What was the value of the Eagle Valley CCGT peak power hedge as compared to realized daily pricing?

A79. For the historical FAC period the peak power purchased realized gains of $758,807 for the month of June, 2021 and $832,168 for the month of July 2021. These gains benefitted the customer by offsetting the cost of purchase power during the corresponding periods of FAC 133 and reflect the risk reduction targeted by entering into the power hedges – locking in a fixed price for MWh corresponding to the hedges. Workpaper DJ-2 included with this filing provides the calculation detail. Realized values for August 2021 and September 2021 will reported in FAC 134.

Q80. What were the factors that impacted the value of the Eagle Valley CCGT peak power hedge?

A80. The two significant factors which impacted the value of the peak power hedges were rising natural gas prices and periods of high temperatures that both contributed to increased power price. For the period of June 1, 2021 through July 31, 2021, Henry Hub natural gas prices rose from $2.91/MMBtu to $4.02/MMBtu from June 1 to July 30, which impacted generation cost of power and drove peak power prices to higher levels. For Indianapolis, June and July temperature variation from normal was +1.6 degrees and -0.9 degrees, respectively. Both months experienced days above 90 degrees. Additionally, there were periods of high temperatures across the northern regions of MISO which impacted the price of power.

Q81. Do the Company's FAC schedules separately identify realized gains or losses from financial hedges, including any associated transaction costs, arising from AES Indiana's power hedges?

A81. Yes, <u>Attachment NHC-1</u>, Schedule 5, Line 20 is used to separately identify these values. There were no transaction costs associated with these hedge transactions.

Q82. Has AES Indiana included additional information regarding the completed hedging transactions as a part of its standard FAC audit package?

A82. Yes. IPL'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

Q83. Did AES Indiana engage in natural gas hedging for Eagle Valley CCGT during the months of May 2021 through July 2021?

A83. No. Due to the Eagle Valley CCGT outage natural gas hedges were not transacted.

Q84. Did AES Indiana transact any financial hedges for the Eagle Valley CCGT during the May 2021 through July 2021 period?

A84. No.

Q85. 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?

A85. 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. As discussed in Q&A 80 above, there are gains included associated with power hedging.

Q86. Has IPL included additional information regarding the completed hedging transactions as part of its standard FAC audit package?

A86. Yes. Consistent with my testimony in FAC 122, IPL'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). This confidential information provides additional details as to the facts and circumstances as they existed at the time the hedging transactions were entered into.

AES INDIANA FUEL HEDGING POLICY

Q87. Is AES Indiana providing an update on its fuel hedging policy?

A87. Yes. The policy incorporates an integrated approach to fuel hedges of coal for Petersburg Station and fixed priced natural gas hedging for the Eagle Valley CCGT. The policy is included as Confidential Attachment DJ-5.

Q88. How will the hedge policy benefit AES Indiana customers?

A88. The policy presents hedge target matrixes for coal and natural gas that the Company will follow to secure specified hedge percentages. The hedges will safeguard customers against price volatility associated with the coal and natural gas markets. Unlike the natural gas hedging program introduced in FAC 122, AES Indiana will act programmatically to complete hedges to insure specified hedge percentages are fulfilled. Additionally, natural gas hedge volumes will vary by season to protect volatility in high demand periods. Other customer benefits associated with AES Indiana's hedge policy include: (a) improved reliability of IPL's natural gas fuel supply and the mitigation of scarcity risk in the winter months, as experienced in February 2021; (b) opportunities to capture locational value opportunities, which lower fuel costs versus Henry Hub pricing; (c) preservation of contracted firm pipeline transportation to support the needs of IPL's natural gas peaker fleet; and (d) reduced need to purchase all of IPL's natural gas requirements in the day-ahead and real-time natural gas markets, which reduces the risk of volume-based pricing.

Q89. What trading instruments will AES Indiana use for natural gas hedging?

A89. As discussed in FAC 122, AES Indiana will consider both financial and physical trading instruments to hedge natural gas. Financial trading instruments include commodity futures and swap contracts. A commodity futures financial contract obligates a buyer to purchase a commodity at a predetermined future date and price. A swap contract is an agreement between two parties to exchange a series of cash flows generated by price changes in the contract's underlying physical commodity. The underlying physical commodity is not physically transferred at settlement. Physical trading instruments are contracts that guarantee delivery of natural gas at the asset at a predetermined price (which may be fixed or based on a price index).

Q90. How will AES Indiana implement the natural gas hedges in the fuel hedging policy?

A90. AES Indiana plans to transact natural gas hedges for the December 2021 through February 2022 due to price volatility that occurs in the winter period. Due to the extreme volatility in February 2021, it is appropriate risk management to ensure natural gas hedges are transacted for the coming winter. If the hedge policy is approved by the Commission, we would begin the programmatic approach to natural gas hedging outlined in the hedge policy.

Q91. How does the AES Indiana hedge policy impact coal hedges?

A91. Length of term and hedge percentages have changed in the fuel hedging policy and are outlined in the Confidential Attachment DJ-5. AES Indiana plans to review the changes with the OUCC during their audit for FAC 133.

Q92. Please describe the internal approval and oversight process AES Indiana will use to manage the hedging policy?

A92. AES Indiana's hedge policy for coal and natural gas hedging, volumes and length of term, are first approved by AES Risk Management and Risk Oversight Committees. AES Indiana's internal Risk Group has oversight of market transactions, including any hedging transactions, and will verify that any completed hedging transactions are consistent with our hedging policy. The Risk Group oversight process includes confirming that transactions adhere to position and term limits and that AES Indiana is only transacting with counterparties that have appropriate credit.

Q93. Is AES Indiana requesting Commission approval of the hedge policy?

A93. Yes. The Company seeks approval from the Commission to be able to pass all hedging gains and losses, including any associated transactional costs, through AES Indiana's FAC. For physical contracts, the fuel cost is seen as a realized cost of fuel, rather than a financial settlement. Because the hedging plan is undertaken for the benefit of customers, the associated costs are appropriately passed to the customer. Specific hedging transactions will be subject to review in subsequent FACs to confirm the Company is following the hedging policy.

Q94. How will AES Indiana's hedges be reflected in AES Indiana's FAC filing?

A94. Known hedges will be reflected in the energy cost forecast in each FAC filing based on the then current forward prices and fixed pricing of coal and natural gas hedges. For natural gas, in the reconciliation process, the actual costs will be reflected as a credit or debit to the price paid for the physical natural gas. The hedge policy will have no impact to the benchmark calculation for purchased power, which will be calculated versus the daily market price of Henry Hub natural gas, plus the $.60/MMBtu delivery cost calculated at a 12.5 heat rate.

Q95. How will the Commission and OUCC be able to review hedge transactions as a part of the FAC proceedings?

A95. AES Indiana understands the need for supporting documentation available for review as part of the FAC process. As noted above, our natural gas hedging positions will be maintained in a deal capture system. This will provide transparency and allow the hedges to be assessed for compliance with our hedging plan based on circumstances as they existed at the time the hedging decision was made. AES Indiana will include in its standard FAC audit package the following types of information for completed hedging transactions: Eagle Valley projected burns; regional pricing (for example, daily index snapshots); pipeline transport information (for example, forward locational gas prices); executed hedges (including transactional costs); and hedge exits (including profit and loss information). Coal contracts will be provided as support to the OUCC as they are in the current FAC proceedings.

Q96. Will AES Indiana review plan performance and propose changes?

A96. Yes. AES Indiana will review hedging performance quarterly to verify the hedges are mitigating coal and natural gas price risk as anticipated. We will update the Commission and the OUCC on any changes to the hedging policy through future FAC filings.

Q97. Is AES Indiana's hedge policy a reasonable means of mitigating natural price volatility risk?

A97. Yes. Fuel costs represent a significant component of overall electric service rates for all classes of AES Indiana's customers. These costs are impacted by a wide variety of factors, some of which are outside of the Company's control. Hedging Eagle Valley CCGT natural gas is an appropriate risk management tool that allows the Company to mitigate exposure to natural gas supply price risk. The mitigation of price risk in fuel procurement is consistent with the FAC "(d)(1)" test because the implementation of a hedging plan is a reasonable action undertaken to provide electricity to customers at the lowest fuel cost reasonably possible. The changes in the Company's proposal reasonably balances the need for flexibility to respond to market conditions with the need for transparency in the regulatory process. It is important to keep in mind that hedging is not done with the promise to reduce overall costs or rates. Rather, the objective is to mitigate exposure to potentially higher costs and to stabilize costs for the ultimate benefit of our customers. Hedging transactions will be reviewed based upon an analysis of the facts and circumstances as they existed at the time the transactions at issue were entered into. If the Commission finds the transactions were reasonable, incurred gains or losses, including any associated transactional costs, will be recoverable through the FAC. Therefore, the Company's proposal is reasonable and should be approved.

SHORT TERM MODEL

Q98. Please discuss the short-term model AES Indiana uses to support and track the Petersburg unit commitment decisions.

A98. 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.

Q99. Will the Company make the model available to the OUCC during its FAC audit?

A99. AES Indiana will include model output from May 2021 through the end of July 2021 in the OUCC packet for review and will review the model and output with the OUCC during the audit as requested.

CONCLUSION

Q100. 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?

A100. 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.

Q101. Does this conclude your prefiled direct testimony?

A101. 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 September, 2021.

David Jackson

INDIANAPOLIS POWER & LIGHT COMPANY

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-May-21	2.8600	0.600	3.4600	12,500	43.25
2-May-21	2.8600	0.600	3.4600	12,500	43.25
3-May-21	2.8600	0.600	3.4600	12,500	43.25
4-May-21	2.9600	0.600	3.5600	12,500	44.50
5-May-21	3.0000	0.600	3.6000	12,500	45.00
6-May-21	2.9900	0.600	3.5900	12,500	44.88
7-May-21	2.9000	0.600	3.5000	12,500	43.75
8-May-21	2.9000	0.600	3.5000	12,500	43.75
9-May-21	2.9000	0.600	3.5000	12,500	43.75
10-May-21	2.9000	0.600	3.5000	12,500	43.75
11-May-21	2.9300	0.600	3.5300	12,500	44.13
12-May-21	2.9100	0.600	3.5100	12,500	43.88
13-May-21	2.9100	0.600	3.5100	12,500	43.88
14-May-21	2.9500	0.600	3.5500	12,500	44.38
15-May-21	2.9500	0.600	3.5500	12,500	44.38
16-May-21	2.9500	0.600	3.5500	12,500	44.38
17-May-21	2.9500	0.600	3.5500	12,500	44.38
18-May-21	2.9900	0.600	3.5900	12,500	44.88
19-May-21	2.9600	0.600	3.5600	12,500	44.50
20-May-21	2.8800	0.600	3.4800	12,500	43.50
21-May-21	2.8600	0.600	3.4600	12,500	43.25
22-May-21	2.8400	0.600	3.4400	12,500	43.00
23-May-21	2.8400	0.600	3.4400	12,500	43.00
24-May-21	2.8400	0.600	3.4400	12,500	43.00
25-May-21	2.7800	0.600	3.3800	12,500	42.25
26-May-21	2.8700	0.600	3.4700	12,500	43.38
27-May-21	2.9100	0.600	3.5100	12,500	43.88
28-May-21	2.8500	0.600	3.4500	12,500	43.13
29-May-21	2.9100	0.600	3.5100	12,500	43.88
30-May-21	2.9100	0.600	3.5100	12,500	43.88
31-May-21	2.9100	0.600	3.5100	12,500	43.88

Day	Daily Average $/MMBtu	Transport Charges $/MMBtu	Proxy Gas Price $/MMBtu	Heat Rate BTU/KWH	Daily Benchmark $/MWH
1-Jun-21	2.9100	0.600	3.5100	12,500	43.88
2-Jun-21	3.0200	0.600	3.6200	12,500	45.25
3-Jun-21	3.0900	0.600	3.6900	12,500	46.13
4-Jun-21	3.0100	0.600	3.6100	12,500	45.13
5-Jun-21	3.0100	0.600	3.6100	12,500	45.13
6-Jun-21	3.0100	0.600	3.6100	12,500	45.13
7-Jun-21	3.0100	0.600	3.6100	12,500	45.13
8-Jun-21	2.9800	0.600	3.5800	12,500	44.75
9-Jun-21	3.1100	0.600	3.7100	12,500	46.38
10-Jun-21	3.1300	0.600	3.7300	12,500	46.63
11-Jun-21	3.1300	0.600	3.7300	12,500	46.63
12-Jun-21	3.2300	0.600	3.8300	12,500	47.88
13-Jun-21	3.2300	0.600	3.8300	12,500	47.88
14-Jun-21	3.2300	0.600	3.8300	12,500	47.88
15-Jun-21	3.3600	0.600	3.9600	12,500	49.50
16-Jun-21	3.3100	0.600	3.9100	12,500	48.88
17-Jun-21	3.2500	0.600	3.8500	12,500	48.13
18-Jun-21	3.2400	0.600	3.8400	12,500	48.00
19-Jun-21	3.2300	0.600	3.8300	12,500	47.88
20-Jun-21	3.2300	0.600	3.8300	12,500	47.88
21-Jun-21	3.2300	0.600	3.8300	12,500	47.88
22-Jun-21	3.1500	0.600	3.7500	12,500	46.88
23-Jun-21	3.2100	0.600	3.8100	12,500	47.63
24-Jun-21	3.3600	0.600	3.9600	12,500	49.50
25-Jun-21	3.3000	0.600	3.9000	12,500	48.75
26-Jun-21	3.4000	0.600	4.0000	12,500	50.00
27-Jun-21	3.4000	0.600	4.0000	12,500	50.00
28-Jun-21	3.4000	0.600	4.0000	12,500	50.00
29-Jun-21	3.6200	0.600	4.2200	12,500	52.75
30-Jun-21	3.7500	0.600	4.3500	12,500	54.38

Day	Daily Average $/MMBtu	Transport Charges $/MMBtu	Proxy Gas Price $/MMBtu	Heat Rate BTU/KWH	Daily Benchmark $/MWH
1-Jul-21	3.7900	0.600	4.3900	12,500	54.88
2-Jul-21	3.7600	0.600	4.3600	12,500	54.50
3-Jul-21	3.6700	0.600	4.2700	12,500	53.38
4-Jul-21	3.6700	0.600	4.2700	12,500	53.38
5-Jul-21	3.6700	0.600	4.2700	12,500	53.38
6-Jul-21	3.6700	0.600	4.2700	12,500	53.38
7-Jul-21	3.6800	0.600	4.2800	12,500	53.50
8-Jul-21	3.6600	0.600	4.2600	12,500	53.25
9-Jul-21	3.5600	0.600	4.1600	12,500	52.00
10-Jul-21	3.7100	0.600	4.3100	12,500	53.88
11-Jul-21	3.7100	0.600	4.3100	12,500	53.88
12-Jul-21	3.7100	0.600	4.3100	12,500	53.88
13-Jul-21	3.7000	0.600	4.3000	12,500	53.75
14-Jul-21	3.7800	0.600	4.3800	12,500	54.75
15-Jul-21	3.8000	0.600	4.4000	12,500	55.00
16-Jul-21	3.6800	0.600	4.2800	12,500	53.50
17-Jul-21	3.7000	0.600	4.3000	12,500	53.75
18-Jul-21	3.7000	0.600	4.3000	12,500	53.75
19-Jul-21	3.7000	0.600	4.3000	12,500	53.75
20-Jul-21	3.7500	0.600	4.3500	12,500	54.38
21-Jul-21	3.8200	0.600	4.4200	12,500	55.25
22-Jul-21	3.9400	0.600	4.5400	12,500	56.75
23-Jul-21	4.0200	0.600	4.6200	12,500	57.75
24-Jul-21	4.1100	0.600	4.7100	12,500	58.88
25-Jul-21	4.1100	0.600	4.7100	12,500	58.88
26-Jul-21	4.1100	0.600	4.7100	12,500	58.88
27-Jul-21	4.0900	0.600	4.6900	12,500	58.63
28-Jul-21	4.1500	0.600	4.7500	12,500	59.38
29-Jul-21	4.1000	0.600	4.7000	12,500	58.75
30-Jul-21	4.0300	0.600	4.6300	12,500	57.88
31-Jul-21	3.9400	0.600	4.5400	12,500	56.75

INDIANAPOLIS POWER & LIGHT COMPANY
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	5/11/2021	$ 8,581	171	$ 1,035	-	$ -		-	$ -
2	5/19/2021	$ 44,753	925	$ 3,591	-	$ -		-	$ -
3	5/20/2021	$ 22,506	443	$ 3,236	443	$ 3,236	Economic Purchases due to Unit Outages and Derates	-	$ -
4	5/22/2021	$ 94,647	783	$ 60,978	-	$ -		-	$ -
5	5/23/2021	$ 105,350	1,668	$ 33,626	1,557	$ 31,295	Economic Purchases due to Unit Outages	-	$ -
6	5/24/2021	$ 355,526	5,680	$ 111,286	5,384	$ 105,687	Economic Purchases due to Unit Outages	-	$ -
7	5/25/2021	$ 539,796	7,820	$ 209,401	7,156	$ 196,781	Economic Purchases due to Unit Outages and Derates	-	$ -
8	5/26/2021	$ 124,102	2,372	$ 21,204	2,224	$ 19,867	Economic Purchases due to Unit Outages	-	$ -
9	5/27/2021	$ 390,500	5,588	$ 145,299	4,512	$ 130,132	Economic Purchases due to Unit Outages	-	$ -
	May Total		25,450	$ 589,655	21,276	$ 486,998		-	$ -
10	6/4/2021	$ 104,837	2,111	$ 9,568	1,679	$ 7,624	Economic Purchases due to Unit Outages and Derates	-	$ -
11	6/5/2021	$ 66,620	1,186	$ 13,096	1,038	$ 11,484	Economic Purchases due to Unit Outages and Derates	-	$ -
12	6/6/2021	$ 2,565	41	$ 715	-	$ -		-	$ -
13	6/7/2021	$ 13,291	228	$ 3,002	-	$ -		-	$ -
14	6/8/2021	$ 234,235	4,172	$ 47,538	2,157	$ 15,913	Economic Purchases due to Unit Outages and Derates	-	$ -
15	6/9/2021	$ 220,512	2,777	$ 91,715	2,113	$ 67,182	Economic Purchases due to Unit Outages and Derates	-	$ -
16	6/10/2021	$ 315,463	5,132	$ 76,158	4,320	$ 66,250	Economic Purchases due to Unit Outages and Derates	-	$ -
17	6/11/2021	$ 312,967	6,158	$ 25,820	5,973	$ 25,047	Economic Purchases due to Unit Outages and Derates	-	$ -
18	6/12/2021	$ 283,166	4,815	$ 52,624	4,667	$ 51,000	Economic Purchases due to Unit Outages and Derates	-	$ -
19	6/13/2021	$ 95,092	1,704	$ 13,505	1,593	$ 12,624	Economic Purchases due to Unit Outages	-	$ -
20	6/14/2021	$ 169,260	2,968	$ 27,152	2,746	$ 25,090	Economic Purchases due to Unit Outages and Derates	-	$ -
21	6/15/2021	$ 81,515	1,561	$ 4,246	603	$ 1,487	Economic Purchases due to Unit Outages and Derates	-	$ -
22	6/17/2021	$ 49,325	927	$ 4,709	113	$ 858	Economic Purchases due to Unit Outages	-	$ -
23	6/18/2021	$ 38,414	736	$ 3,086	198	$ 255	Economic Purchases due to Unit Outages and Derates	-	$ -
24	6/20/2021	$ 11,946	245	$ 216	-	$ -		-	$ -
25	6/25/2021	$ 33,330	213	$ 22,946	-	$ -		-	$ -
26	6/26/2021	$ 31,413	613	$ 763	237	$ 267	Economic Purchases due to Unit Outages	-	$ -
27	6/28/2021	$ 5,246	99	$ 296	62	$ 185	Economic Purchases due to Unit Outages and Derates	-	$ -
28	6/29/2021	$ 51,242	808	$ 8,620	319	$ 2,208	Economic Purchases due to Unit Outages and Derates	-	$ -
	Jun Total		36,494	$ 405,772	27,818	$ 287,474		-	$ -
29	7/2/2001	$ 103,340	1,137	$ 41,374	-	$ -		-	$ -
30	7/5/2021	$ 118,397	1,669	$ 29,306	1,484	$ 26,271	Economic Purchases due to Unit Outages and Derates	-	$ -
31	7/6/2021	$ 456,260	7,260	$ 68,722	6,707	$ 56,228	Economic Purchases due to Unit Outages and Derates	-	$ -
32	7/7/2021	$ 42,148	768	$ 1,060	731	$ 1,009	Economic Purchases due to Unit Outages	-	$ -
33	7/14/2021	$ 28,817	474	$ 2,866	-	$ -		-	$ -
34	7/15/2021	$ 1,434	24	$ 114	24	$ 114	Economic Purchases due to Unit Outages	-	$ -
35	7/19/2021	$ 81,735	1,371	$ 8,044	489	$ 2,755	Economic Purchases due to Unit Outages and Derates	-	$ -
36	7/20/2021	$ 31,377	488	$ 4,840	488	$ 4,840	Economic Purchases due to Unit Outages and Derates	-	$ -
37	7/22/2021	$ 12,696	145	$ 4,467	-	$ -		-	$ -
38	7/23/2021	$ 15,548	240	$ 1,688	-	$ -		-	$ -
39	7/24/2021	$ 63,835	438	$ 38,045	364	$ 30,202	Economic Purchases due to Unit Outages and Derates	-	$ -
40	7/28/2021	$ 8,937	129	$ 1,277	92	$ 911	Economic Purchases due to Unit Outages and Derates	-	$ -
41	7/29/2021	$ 4,069	53	$ 955	35	$ 631	Economic Purchases due to Unit Outages and Derates	-	$ -
	Jul Total		14,196	$ 202,756	10,414	$ 122,960		-	$ -
	Grand Total			$ 1,198,183		$ 897,432			$ -

[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--3

[Confidential Attachment]

<u>CONFIDENTIAL Attachment DJ--4</u>

[Confidential Attachment]

CONFIDENTIAL Attachment DJ--5

[Confidential Attachment]

CONFIDENTIAL Attachment DJ--6

[Confidential Attachment]