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STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

SUBDOCKET FOR REVIEW OF INDIANAPOLIS POWER & LIGHT COMPANY D/B/A AES INDIANA'S 2021 EXTENDED FORCED OUTAGE AT EAGLE VALLEY AND ITS RELATED IMPACT ON FUEL PROCUREMENT AND FUEL COSTS	**CAUSE NO. 38703-FAC133 S1**

Verified Direct Testimony and Attachment of

Michael P. Gorman

REDACTED VERSION

On behalf of

AESI Industrial Group

August 29, 2022

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Verified Direct Testimony of Michael P. Gorman

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Michael P. Gorman. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and a Managing Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to this testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A The AES Indiana Industrial Group ("IG"). Industrial Group members purchase substantial quantities of electric energy service from Indianapolis Power & Light Company d/b/a AES Indiana ("AESI", "IPL" or "Company"). As customers of AESI, then, they have a substantial stake in the outcome of this proceeding as they will experience rate impacts depending on the final resolution by the Indiana Utility Regulatory Commission ("IURC" or "Commission").

Q PLEASE DESCRIBE AESI'S FILING IN THIS SUBDOCKET.

A The AES filing in this subdocket concerns the responsibility for, and impact of, Fuel Adjustment Charge ("FAC") costs to be recovered related to the extended forced outage at the Eagle Valley combined cycle gas turbine ("CCGT") which lasted from April 25, 2021 through March 18, 2022.

There are several issues raised by AESI's filing for the Commission's consideration. Among these issues are whether AESI is responsible for the forced outages at Eagle Valley, the amount of replacement fuel costs incurred as a result of those outages, and whether or not fuel costs related to the outages should be recovered directly from customers, or should be the responsibility of AESI or other parties.

Q PLEASE DISCUSS THE FORCED OUTAGES AT EAGLE VALLEY WHICH LED TO THIS SUBDOCKET.

A Eagle Valley CCGT plant ("Eagle Valley") is a modern 671 MW natural gas-fired combined cycle turbine facility operated by AESI that went online on April 28, 2018. On April 25, 2021, during startup following a scheduled maintenance outage, the plant experienced a problem that caused a forced outage at the plant. ("Incident 1A"). Once the repairs had been complete following Incident 1A, AESI attempted to restart the plant again in November, 2021. On November 10, 2021, during that startup attempt, the plant experienced a second forced outage and also experienced serious damage to the plant's turbine and steam system. ("Incident 1B").

Eagle Valley ultimately returned to service on March 18, 2022. The combination of Incidents 1A and 1B resulted in the Eagle Valley CCGT being in a continuous forced outage status for 327 days, from April 25, 2021 through March 18, 2022. During this forced outage period, AESI's FAC fuel cost increases over the fuel costs included in base rates were deferred for FACs 133, 134, 135, and 136 until the Commission could make a determination as to the cause and responsibility of the forced outages, and to determine the recoverability of the fuel cost increases.

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A My testimony addresses AESI's errors, imprudent actions, failed operator training, and mistaken assumptions that place ultimate responsibility on AESI for both Incident 1A and 1B and the resulting combined forced outages which lasted nearly a full year. I will analyze the material factors which caused the forced outages related to both incidents based on AESI's own internal investigation, specifically its Root Cause Analyses, of the factors which led to the outages. I will discuss why both Incident 1A and 1B are the result of AESI's own errors and imprudence. My conclusion is that as a result of the outages being ultimately attributable to AESI's own failure to conform to the appropriate standard of care for a utility in operating a major generation asset, any fuel cost increase due to the outages should not burden AESI customers who bear no responsibility for causing the outages that led to the increased fuel costs during the outage period.

Secondly, I will discuss the inaccuracy of the Company's estimate of the $41,518,476 increase to fuel cost caused by the Eagle Valley forced outages. I will discuss why the Company incorrectly underestimated the increased fuel costs and has not demonstrated the accuracy of its own estimate. In place of AESI's underestimate of the impact of the outages, I will provide a computation of my own estimate based on AESI's dispatchable Eagle Valley output (kWh) and its displacement of MISO market purchases and ability to increase Off-System Sales, had Eagle Valley not been in the forced outage (Non-Outage Scenario). Finally, I compute an appropriate refund for FAC savings had Eagle Valley been available during the outage period, and propose a credit to be computed and applied in future FAC periods for AESI customers, with interest.

Q DO YOU HAVE ANY EXPERIENCE REGARDING EVALUATING THE ACTIONS OF UTILITIES WITH REGARDS TO THE OPERATION OF THEIR FACILITIES AND THE RESULTING CALCULATION OF COSTS RELATED TO OUTAGES SUCH AS THAT AT EAGLE VALLEY?

A Yes. I have testified in numerous cases in numerous jurisdictions on these matters. Most recently, in Indiana, I provided testimony in Cause No. 38706 FAC 130-S1 which involved analysis of comparable issues as they related to the fire at NIPSCO's R.M. Schahfer Generation Station which caused so much damage it ultimately led NIPSCO to retire Units 14 and 15 at that facility.

Q DOES THE FACT THAT YOU DID NOT ADDRESS EVERY ISSUE RAISED IN AESI'S TESTIMONY MEAN THAT YOU AGREE WITH THE COMPANY'S TESTIMONY ON THOSE ISSUES?

A No. It merely reflects that I chose not to address all those issues in my testimony. It should not be read as an endorsement of, or agreement with, or acquiescence of AESI's positions on such issues.

I. EAGLE VALLEY OPERATING HISTORY

Q PLEASE DESCRIBE AESI'S EAGLE VALLEY CCGT.

A Eagle Valley is a 671 MW gas-fired combined cycle gas turbine ("CCGT") located in Morgan County, Indiana. The plant consists of two GE 7FA.05 gas turbines gas turbines, associated Nooter Eriksen heat recovery steam generators, and a Toshiba steam turbine. Eagle Valley began commercial operations on April 28, 2018, the date AESI took ownership and control of the CCGT from EPC Contractors, whom the Company had selected to develop and construct the plant.

Eagle Valley is a modern CCGT plant with advanced automated control systems that assist in plant operation. The control systems are comprised of General Electric Mark Vie for control of the gas turbine-generators, the Toshiba Microprocessor Aided Power system control ("TOSMAP") for the control of the steam turbine-generator and the Emerson Ovation Distributed Control System ("DCS") that controls the balance of plant, including but not limited to the Heat Recovery Steam Generators, Boiler Feedwater and Steam Systems.[1]

AESI placed Eagle Valley in-service for commercial operation and sought inclusion of the costs in its tariff rates April 28, 2018.[2] The Commission approved including in rates the non-fuel costs of these facilities at an annual revenue requirement of approximately $55 million, based on a rate base cost of $677 million.[3] In that Cause No. 45029, AESI sought to include Eagle Valley in rate base following resolution a dispute between AESI and its Engineering Procurement Contractor ("EPC") for delaying the in-service date of the facility.[4]

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[1]Direct Testimony of John Bigalbal at 6-8.
[2] See Cause No. 45029, Order October 31, 2018, at 1 and 28.
[3]*Id*. at 12.
[4]Cause No. 45029, Final Order at 12.

At that time, the Company represented that Eagle Valley would provide capacity and low-cost energy service to its retail customers.[5]

Q DID THE COMPANY PROVIDE A HISTORY OF EAGLE VALLEY'S OPERATING HISTORY PRIOR TO INCIDENT 1A AND 1B?

A Yes. AESI witness John Bigalbal provides this background. Eagle Valley commenced commercial operations on April 28, 2018. Since that time, the plant was rarely shut down for maintenance. Operators at Eagle Valley performed only five cold starts post-commercial operation and prior to Incident 1A.[6] During periods when Eagle Valley did not experience a forced outage of significant duration, it operated at a high capacity factor, approximately 85% in 2019 and 2020,[7] which signifies that it was economically advantageous, low fuel cost, facility to operate the majority of the time.

Q DOES AESI'S DATA SUGGEST DIFFICULTY STARTING EAGLE VALLEY FROM A COLD START PRIOR TO ITS COMMERCIAL OPERATION DATE?

A The Company's response to IG DR 4-1 Revised Confidential Attachment 1, included in Confidential Attachment MPG-1, illustrates **[redacted]**. Indeed, this data response illustrates **[redacted]**. This startup history strongly indicates that AESI must prove that its decision to place this unit in-service on April 28, 2018 was reasonable and prudent, and whether or not the plant had been thoroughly

[5]Cause No. 45029, Verified Direct Testimony of Bradley Scott, and Heat Rate for Eagle Valley, and AESI response to IG DR 7-1, provided in Attachment MPG-1.
[6]IG DR 4-2, provided in Attachment MPG-1.
[7]Direct Testimony of John Bigalbal at 6.

tested by its major equipment manufacturers, Toshiba, General Electric and Nooter Eriksen, to ensure that it was ready to provide service on a sustained and reliable basis to AESI and its customers.

Q HOW DOES EAGLE VALLEY HISTORICAL PERFORMANCE COMPARE TO OTHER MODERN CCGT PLANTS?

A Eagle Valley's historical performance for the period May 2018 through December 2021 is well below average when compared to other National Gas Combined Cycle plants ("NGCC") in the same time period. Table 1 below compares the forced outage rate of Eagle Valley to the forced outage rate of all natural gas combined cycle plants reporting to North American Electric Reliability Corporation ("NERC") - 342 NGCC plants over the period 2017 through 2021.

As can be seen from Table 1, NGCC plants generally have a very low forced outage rate of only 4.4%; however, during the period from May 2018 to December 2021, Eagle Valley had a forced outage rate of **[redacted]** than other NGCC plants. The fire in 2018 and Incidents 1A and 1B at the plant unquestionably had a material impact on its reliability. This is clearly illustrated in comparison of its outage rate compared to that of other plants.

TABLE 1

Eagle Valley Forced Outage Rate

Description	Forced Outage Rate (%)
Eagle Valley May 2018-December 2021[1]	** [redacted] **
All Natural Gas Combined Cycle Plants 2017-2021[2]	4.4%

Sources:
[1] IG DR 4-3 Confidential Attachment 1
[2] NERC GADS Generating Data Brochure 2017-2021.

For the relatively new Eagle Valley plant, the availability and the reliability of the plant was severely impacted by the two forced outage incidents, but, significantly, customers continued to pay through rates for the plant's capital and fixed operating costs as though it was continually performing in a reliable and efficient manner.

II. FORCED OUTAGES AT EAGLE VALLEY

Q PLEASE PROVIDE AN OVERVIEW OF INCIDENT 1A.

A Incident 1A caused a forced outage at Eagle Valley that lasted from April 25, 2021 to November 10, 2021. On April 25, 2021, Eagle Valley was returning from a scheduled maintenance outage and began the process of a cold start to return to service. During startup, the Steam Gas Turbine 1 ("STG1") experienced an issue with the 52GX1 breaker which prevented the facility from connecting with the grid. More specifically, the control system showed the breaker open in one location and closed in another, which prevented it from synchronizing with the grid. AESI personnel on-duty at the time decided to shut down the unit for the night and try again the next day.[8] During the coast down resulting from that decision the 86G1 and 86G2 lockout relays were activated, which should have opened the field breaker - identified as the 41E Breaker. However, due to the **[redacted]**[9] and the unit was not able to synchronize to the grid.

Once the turbine completed its coast down and was placed on turning gear, the 86G relays were reset, and because the 41E break was closed, the Automatic Voltage Regulator ("AVR") was put into service. Fourteen minutes after the 86G relays were reset, the 86ET lockout relay tripped, meaning the Excitation Transformers were not protected, and it was at this time that the field ground happened.[10] AESI found that the field ground caused the severe damage which required that the entire plant be placed into forced outage status.

AESI's root cause analysis identified several factors which led to the forced outages including:

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[8] *Id*. at 16.
[9] Confidential Direct Testimony of AES Indiana Witness Bigalbal, Page 13.
[10] *Id*. at 8.

TABLE 2

Identified Root Causes

Title	Node Type
➢ Jumper wire became disconnected from terminal	Physical Root
➢ AVR sent excitation voltage and current to field while turbine on turning gear	Physical Root
➢ 86G1 and 85G2 Lockouts were reset without a coordinated effort with operations to confirm the reason they tripped and then monitor the conditions after they were reset	Human Root
➢ Loose wires with exposed conductive ends not recognized as a questionable situation which should be reported for resolution	Human Root
➢ Jumper wire in STG Generator Circuit Breaker cabinet not installed in accordance with OEM standards	Human Root
➢ Toshiba AVR logic prevented any 41E Breaker Open signal due to programed interlocks based on signal from 52GX1 Relay indicating 52G Breaker status as Closed	Latent Root
➢ All signals (Logic and Hardwired) to Open 41E Breaker were blocked by the 52GX1 Relay N/C contact, a Toshiba designed hardwired interlock	Latent Root
➢ TOSMAP responded as designed to an incorrect 52G Breaker status indicator as it had no means to verify the accuracy of the indirect 52G Breaker status indication provided through the 52GX1 Relay	Latent Root
➢ TOSMAP logic did not detect different status indications displayed on the OPS for 52G Breaker by the AVR and by the EHC microprocessors	Latent Root
➢ Incorrect Generator Protection Control system initialization issue of 52G Breaker Close indication with 41E Breaker Open not recognized by personnel nor TOSMAP controls	Latent Root
➢ Wiring connection drawing was incorrect, showed jumper wire connecting between terminals 84 and B10	Latent Root
➢ Lack of a written Standard Operating Procedure detailing personnel responsibilities and actions in response to an 86 Series Lockout Relay trip	Latent Root
➢ Insufficient communication and coordination amongst all onsite personnel to confirm awareness of the potentially damaging conditions presented when the 41E Breaker remained closed as the reason for the Operations Leader's decision for the work stoppage[11]	Latent Root

[11]Petitioner’s Attachment JB-1 PUBLIC, RCA Report, page 8 of 40.

Q PLEASE PROVIDE AN OVERVIEW OF INCIDENT 1B.

A Incident 1B caused a forced outage at Eagle Valley that started on November 10, 2021 and lasted through March 18, 2022. Similar to Incident 1A, Incident 1B occurred during a cold restart of the Eagle Valley Generating Station. On November 8, 2021, after repairs related to Incident 1A had been completed, Gas Turbine 2 ("GT2) was started and connected to the grid at 1:15 P.M. However, when attempting to start the STG1, the TOSMAP system control responsible for providing the communication between the field sensors and the control processors failed to communicate resulting in an unsuccessful start of STG1. While troubleshooting of the STG1 was underway, GT2 was brought up from 16 MW to 90 MW to reach Dry Low NOx Mode 6 due to the operators' lack of understanding of the pollution control requirements.

Approximately 48 hours later, on November 10, 2021 at 1:02 P.M., after the plant had been operating for a period of time, and at a level that far exceeded design specifications, STG1 startup was initiated. GT2 was brought up to Full Speed, No Load (FSNL) operation of 115 MW. As had happened in Incident 1A, the Field Breaker (41E Breaker) did not close and the Automatic Voltage Regulator supplied excitation current to the generator. AES technicians determined that there was not a signal being sent to the 41E Breaker, and the unit was again unable to synchronize to the grid.

AESI concluded that a failed relay on a printed circuit board in the Automatic Voltage Regulator controller caused the problem. However, after the circuit printed board was replaced, the Generator Breaker, 52 G Breaker, failed to close leaving the generator unable to connect to the grid. While the 52G Breaker failure was being investigated, the sound of an explosion was heard in the control room. This explosion was caused by the buildup of steam pressure in the High-Pressure Turbine Exhaust pipe ("HP Exhaust"). The explosion blew a hole in that pipe, and major damage resulted to one of the steam turbines integral to the operation of the plant. Both units, the STG and GT2, were tripped manually, and the operators proceeded with a plant shutdown. The HP Exhaust pipe ruptured after GT2 was in FSNL operation, 115 MW output, for a period of approximately five hours and after numerous warnings regarding the buildup of heat and high pressure were ignored by AESI personnel in the facility's control room.

III. CONTRIBUTING FACTORS TO INCIDENTS 1A AND 1B

Q WHAT IS YOUR UNDERSTANDING OF EAGLE VALLEY'S OPERATIONAL ISSUES PRIOR TO INCIDENT 1A?

A The EPC Contractor selected to perform startup commissioning and warranty testing performed **[redacted]**.[12] During this time period, AESI was responsible for providing proper oversight of the commissioning and warrantying process.[13] On April 28, 2018 AESI took control of the operation of Eagle Valley and filed a report with the Commission that settled any remaining claims with the EPC Contractor.

Following AESI's assumption of operational control of Eagle Valley, the plant continued to experience problems. On August 12, 2018, a fire started in a cable tray located near an exhaust vent that caused a forced outage for 50 days. As a result of this fire AESI had to **[redacted]**.[14] In addition, **[redacted]

[12]IG DR 4-1 Confidential Attachment 1, provided in Confidential Attachment MPG-1.
[13]Cause No. 44339, IPL's Submission of Semi-Annual Progress Report, November 2017, Page 7.
[14]IG DR 4-3 Confidential Attachment 1, provided in Confidential Attachment MPG-1.

[redacted]**.[15]

Eagle Valley cold start issues continued to remained problematic throughout AESI's control and operation of the plant. In four of the five cold-starts prior to Incident 1A, the high HP ("High Pressure") exhaust temperature alarm activated.[16] That is the same alarm that was activated during Incident 1B, and which was ignored by AESI operational personnel in the control room. And on the last cold startup prior to incident 1A, August 16, 2020, plant shutdown occurred because the STG could not increase load since GT-2 would not increase load. The IP Bypass valve was stuck fully open.[17] During the same startup, the temperature matching mode was on and even after the operator pressed the button to turn off temperature matching mode it would not turn off.[18]

Lastly, the Incident 1A and 1B Root Cause Analyses identified that AESI never received **[redacted].**

Q WHAT IS THE SIGNIFICANCE OF THE TTILS?

A TTIL Revision 0 detailed concerns that the steam turbine design was **[redacted]

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[15]IG DR 4-3 Confidential Attachment 1, provided in Confidential Attachment MPG-1.
[16]IG DR 4-2, provided in Attachment MPG-1.
[17]IG DR 4-1, provided in Attachment MPG-1.
[18]IG DR 6-2, provided in Attachment MPG-1.

[redacted].** The Toshiba steam turbine was manufactured in 2015, two years after the publication of the TTIL Revision 0 in 2013. **[redacted].** In addition, **[redacted].** The last TTIL Eagle Valley Leadership received from Toshiba prior to that outage was in August 2018. In February 2021, Toshiba issued a Revision 1 to the TTIL as they were made aware **[redacted].**[19]

Q COULD YOU PLEASE ELABORATE ON WHY NOT ALL OF THE CORRECTIVE ACTIONS RECOMMENDED BY TOSHIBA TTIL REVISION 0 AND REVISION 1 WERE IMPLEMENTED BY AESI?

A. No, there is no clear explanation. The Root Cause Analyses indicate that Eagle Valley leadership was unaware of TTIL Revision issued by Toshiba in 2021 as the Company had, for unknown reasons, been dropped off the distribution list and took no corrective

[19]AES Indiana Attachment AKH-6(C) Page 13 and 14.

action to ensure it remained on the distribution list.[20] Nor is there a clear reason the Company implemented only one of the two corrective actions suggested by Toshiba TTIL 0.

Q COULD YOU PLEASE ELABORATE ON WHY TOSHIBA TTILS ISSUED AFTER AUGUST 2018 WERE NOT DISSEMINATED TO EAGLE VALLEY LEADERSHIP FOR REVIEW AND IMPLEMENTATION?

A. No, AESI did not provide an explanation in the Company's Direct Testimony for this lapse.

Q CAN YOU EXPLAIN WHY IT IS IMPORTANT THAT THE OPERATIONAL HISTORY INDICATES THE SAME PROBLEMS AROSE DURING MULTIPLE COLD-RESTARTS, BUT WENT UNCORRECTED?

A In the cold starts that occurred during Eagle Valley Commissioning, the HP Exhaust High Temperature Alarm only went off on **[redacted]**.[21] However, once AESI took control of Eagle Valley, in four of the five cold start-ups, the HP Exhaust High Temperature Alarm was activated (on the fifth start up the unit was shut down since GT2 could not increase load).[22] The indicated HP Exhaust High Temperature became an issue once AESI took operational control of Eagle Valley. In addition, AESI did not take any corrective actions once they had operational control to address the issues. The fact that the same issues occurred again, and again, with no corrective, or investigative action, being taken suggests a lack of concern and

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[20]AES Indiana Attachment AKH-6(C), Page 13 and 14.
[21]IG DR 4-1 Confidential Attachment 1, provided in Confidential Attachment MPG-1.
[22]IG DR 4-2, provided in Attachment MPG-1.

negligence by AESI and its plant operators as to why a critical issue was occurring at a major generation facility.

Q WHAT IS YOUR UNDERSTANDING OF THE CONTRIBUTING FACTORS THAT LED TO INCIDENT 1A?

A The disconnected jumper wire ultimately lead to the 41E Breaker remaining closed which then caused the AVR to send excitation voltage causing the field ground of the Excitation Transformers. AESI concluded that if the disconnected jumper wire had been connected, Incident 1A would not have occurred.[23] AESI's Incident 1A Root Cause Analysis determined that the jumper wire in the STG Generator Circuit Breaker cabinet was not installed in accordance with original equipment manufacturer (OEM) standards.[24] A contracted technician that was working in the cabinet during the planned maintenance outage prior to Incident 1A later stated he saw the disconnected wire when he started his work but did not report it until he was interviewed after the event.[25] The loose wires with exposed conductor ends were not recognized as a questionable situation or reported to management.[26] The lack of any requirement, or culture mandating to conformity to any requirement to report such an issue, is an indication that AESI's oversight over key systems within the plant was seriously lacking.

However, regardless of the disconnected jumper wire, it was AESI technicians' actions after the 41E Breaker remain closed and the coast down was ordered that led to damage to the Excitation Transformer. AESI personal insufficiently coordinated and communicated to confirm awareness of the damaging conditions presented with the 41E

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[23]Direct Testimony of John Bigalbal at 14.
[24]Incident 1A Root Cause Analysis, page 13.
[25]Direct Testimony of John Bigalbal at 14.
[26]Incident 1A Root Cause Analysis, Page 13.

breaker closed. The 86G1 and 86G2 Lockouts were manually reset without a coordinated effort with AESI operations personnel to confirm the reason they tripped in the first instance, and then monitor the conditions after reset. Once the 86G1 and 86G2 Lockouts were reset, and with the 41E Breaker remaining closed, the conditions necessary for the AVR to send excitation voltage to the field ground were met.[27]

Q WHAT IS YOUR UNDERSTANDING OF THE INTERPLAY OF THE CONTRIBUTING FACTORS THAT LED TO INCIDENT 1B?

A AESI's own Root Cause Analysis identified a number of operational errors that ultimately lead the rupture of the High-Pressure Turbine Exhaust pipe and resulting plant outage of 128 days.[28]

- Initially, when the STG would not start, plant leadership directed plant personnel to disable the auto temperature-matching mode to increase GT2 load to 90MW. The operators questioned the continued operation at the higher load, but management confirmed to maintain operating GT2 at 90 MW as they expected the repairs to be completed soon and the desire was to be ready to restart the STG. However, there was no attempt to restart the STG until 48 hours later.[29]

- The decision by plant management to continue running the GT2 at 90MW was due to an erroneous understanding of relevant environmental requirements. Importantly, the continued operation of GT2 at 90MW contributed to the high-heat and pressure conditions which led to the final, catastrophic, explosion in the HP Exhaust pipe and damage to the turbine.

- HP Steam pressure and temperature supplied to the HP Turbine exceeded Toshiba recommended operation range and no corrective actions were taken to reduce temperature when HP Exhaust high temperature alarm displayed.

- When questioned about how to reduce the HP Exhaust temperature, AESI operators could not recall the process adjustments necessary to lower the temperature indicating a lack of training and knowledge of operating procedures.

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[27] Incident 1A Root Cause Analysis, Page 5 and 8.
[28] Incident 1B Root Cause Analysis.
[29] *Id.*

- Insufficient flow of steam through the HP Turbine to remove heat generated by windage.
- The steam turbine operated for an extended period of time (5 hours and 9 minutes) at Full Speed No Load (FSNL) condition.
- Throughout the November startup event there were many people in the control room, creating distractions to the operators. During the STG startup on November 10, 2021, between 13:00-21:00, 21 AESI personnel entered or exited the control room over 200 times. This does not include the contractors who were escorted into the control room by AESI personnel.
- GT2 ("Gas Turbine 2") was operated at 110 MW prior to STG ("Steam Gas Turbine") going on grid and the STG startup should not have occurred given GT2 operating conditions that exceeded design parameters.
- Startup procedure was flawed because it did not contain stop points to confirm system response and status.
- Lack of operator knowledge of bypass steam process and related controls logic. The Main Steam conditions were far outside of the startup operating criteria. Main Steam pressure reached 1582psi once FSNL was reached. Startup conditions show this should have remained consistent at 1200 psi until load reached 50% before ramping up to 2415 psi. The CRH ("Cold Reheat") condensate drain valve was placed in auto control prior to STG startup when procedure called for manual mode so the valve could be opened. This caused the CRH condensate drain valve to remain closed during startup when it should have been open. In addition, HRSG ("Heat Recovery Steam Generator") startup vent valves were not manually used to adjust main steam conditions.
- The lack of operator knowledge is consistent with a lack of training by AESI of the Eagle Valley personnel. As the Root Cause Analysis makes clear, training for operators, even if they had experience at other steam plants, was very limited, with operators being, largely, asked to review technical manuals entirely on their own, with little to no formal instruction on system operations.

Q IN YOUR OPINION DO THE ROOT CAUSE ANALYSES SUGGEST AESI'S OPERATION OF EAGLE VALLEY TO BE PRUDENT AND REASONABLE?

A No. The Root Cause Analyses identified a number of operational errors that contributed to Incidents 1A and 1B as detailed above.

- ➢ Failure to ensure Eagle Valley start-up was operating consistent with OEM criteria before the facility was declared in commercial operation.
- ➢ Failed AES oversight for noting and correcting flawed wiring.

- AES is responsible for deficient operator training and for the failure to establish standard protocols for startup operations for its operators to follow.
- AES management failure to respond to operator identified warning.[30]
- Insufficient communication and coordination among AESI personnel to recognize hazardous situations.
- Distracting work environments. For example, AESI was responsible for allowing so many persons into the control room during the lead up to incident 1B, contributing to the confusion.
- Lack of knowledge of and implementation of recommendations contained in TTIL updates.
- Lack of knowledge regarding plant control systems and plant operation.
- Operator failure by ignoring system alarms and operating protocols.
- Following proper stop points to avoid hazardous conditions, and avoid equipment failure.

Q BASED UPON THE FINDINGS OF AESI'S OWN ROOT CAUSE ANALYSIS, DO YOU BELIEVE AESI PRUDENTLY OPERATED EAGLE VALLEY?

A No. The Company's operating procedures, its lack of accurate wiring diagrams, and failure of training of operators to follow OEM procedures make a clear finding that AESI should be held accountable for failure of this unit to start up operations starting in April 25, 2021, and extending through the completion of that forced outage through March 18, 2022.

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[30]Incident 1B Root Cause Analysis, Page 15.

IV. IMPACT ON AESI FAC COST DUE TO THE EAGLE VALLEY FORCED OUTAGE

Q PLEASE PROVIDE A BRIEF OVERVIEW OF CONTRACT RIDER 6 – FUEL ADJUSTMENT CHARGE.

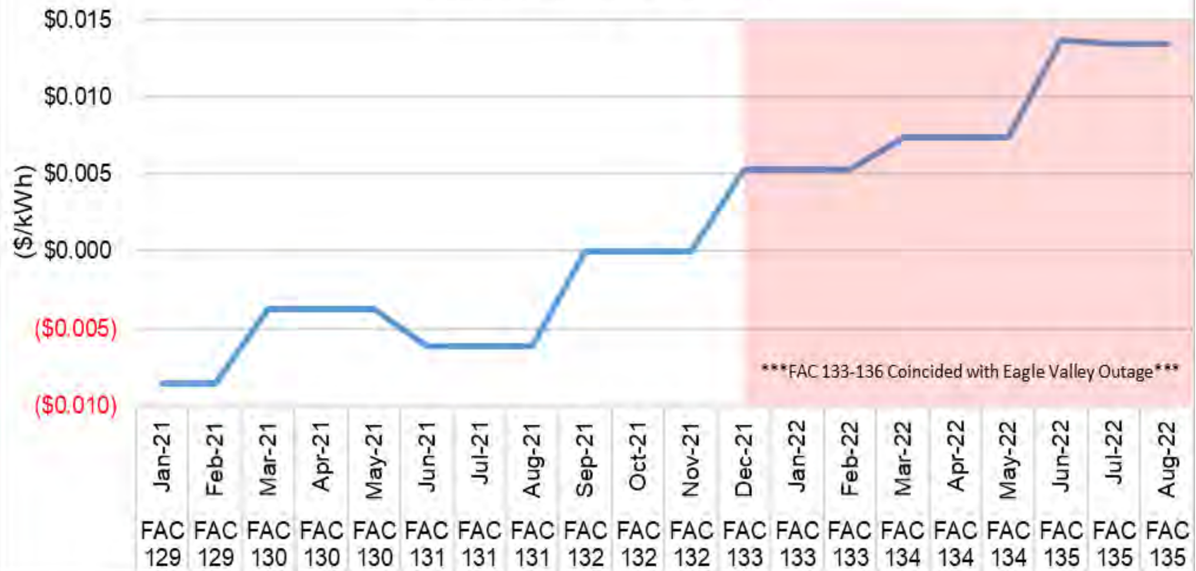
A The Fuel Adjustment Charge ("FAC") is meant to recover the Company's cost of fuel in the Company's own plants or plants jointly owned and leased by the Company plus the energy purchased on an economic dispatch basis less the cost of fuel recovered through intersystem sales and other energy sold on an economic dispatch basis. The sum of these fuel cost are then divided by the estimated kilowatt-hour sales for the FAC period. The FAC may then be modified to reflect the difference between incremental fuel cost billed and incremental fuel cost actually experienced during a historical period.

This is the reason why the fuel cost impact of the Eagle Valley outage, which lasted from May 2021 to March 2022 (historical FAC periods 133-136) is at issue in this sub-docket despite customers being charged under FACs 133-136 for the period December 2021 through November 2022. I have illustrated this in Figure 1 below. Figure 1 also demonstrates that customers are currently being billed at FAC rates greater than the FAC rates from January 2021 through November 2021, despite deferring some of the incremental fuel cost associated with the Eagle Valley forced outage.[31]

[31]Direct Testimony of David Jackson, Page 3.

Figure 1

Contract Rider 6 - FAC History



IV.A. Increased Fuel Cost Due to Outage

Q HAVE YOU ESTIMATED THE INCREASE TO AESI FUEL COST DUE TO THE EAGLE VALLEY OUTAGE FOR FAC 133 THROUGH FAC 136?

A Yes. AESI estimated the Eagle Valley Net energy by month using a production cost model to simulate the plant's output during the outage period.[32] The fuel cost estimated for AESI was made based on the actual FAC periods including the Eagle Valley outage, and an estimate was made had the Eagle Valley generation been available to displace either AESI market purchases, or produce margin via Off-System Sales ("OSS"). The results of this comparison are shown in Attachment MPG-2.

Using the Company's projected monthly energy output of Eagle Valley had the outage not occurred, and its estimated changes in market purchases and sales, I estimated the increased FAC fuel cost caused by the Eagle Valley outage. As shown on

[32]Direct Testimony of David Jackson, Page 7

Attachment MPG-1, and illustrated in Table 3 below, the outage at Eagle Valley resulted in $70.8 million in costs during FAC periods 133-136. This estimate also uses AESI's own estimated dispatch cost for Eagle Valley, and its monthly average MISO purchase and sales price for displaced purchases and increased Off-System Sales.

TABLE 3

Eagle Valley FAC Impact

	Eagle Valley FAC Savings	Eagle Valley FAC Cost	Eagle Valley Cost
FAC 133	$33,109,258	$24,579,287	$8,529,971
FAC 134	$58,058,111	$39,621,398	$18,436,713
FAC 135	$76,337,752	$43,818,442	$32,519,311
FAC 136	$31,836,361	$20,451,529	$11,384,831
TOTAL	$199,341,482	$128,470,657	$70,870,826

Source: Public Attachment MPG-2

V. AESI'S ESTIMATED IMPACT OF EAGLE VALLEY OUTAGE ON FUEL COSTS

Q DID AESI ESTIMATE THE IMPACT ON ITS FAC COST DUE THE OUTAGE OF EAGLE VALLEY?

A Yes. AESI estimated, due to the outage, its fuel cost increase by approximately $41.52 million. This estimate was made by a comparison AESI made of its actual fuel costs to an estimate of what the fuel costs would have been had Eagle Valley been available to operate. As outlined below, however, I believe the Company has overstated its fuel costs with Eagle Valley operating and is therefore understating the amount of increase in fuel costs caused attributable to the Eagle Valley outages.

Q HOW DID AESI DETERMINE ITS ACTUAL FUEL COSTS INCURRED DURING THE FAC PERIODS REFLECTING THE EAGLE VALLEY OUTAGE?

A As shown in Table 4 and according to AES Indiana Attachment DJ-3 the total fuel cost incurred during the outage period was $512.85 million ($45.10/MWh).

TABLE 4

Actual FAC Costs During Eagle Valley Outage

Description	FAC 133	FAC 134	FAC 135	FAC 136	Total
Coal and Oil Generation	$ 43,683,815	$ 44,079,643	$ 42,747,421	$ 38,788,611	$ 169,299,490
Other Generation - Internal Combustion	5,347	3,237	6,166	4,065	18,815
Natural Gas Generation	22,158,606	36,671,447	60,281,747	29,174,341	148,286,141
Financial Hedges Gains/Losses & Transactional Fees	(1,590,974)	(5,635,472)	482,546	-	(6,743,900)
Purchases through MISO					
Wind Purchase Power Agreement Purchases	10,253,574	12,960,067	23,575,450	14,894,202	61,683,293
Non-Wind PPA Market Purchases	24,416,738	29,768,617	44,665,211	14,675,410	113,525,976
Other	4,841	4,993	7,482	13,825	31,141
MISO Components of Cost of Fuel	3,150,352	6,755,564	11,144,778	(3,664,531)	17,386,163
Purchased Power other than MISO	7,707,074	6,708,000	3,424,862	3,190,647	21,030,583
LESS:					
Inter-System Sales through MISO	$ 735,600	$ 2,096,045	$ 2,207,067	$ 4,763,623	$ 9,802,335
Transmission Losses	157,207	290,683	253,044	390,912	1,091,846
Lakefield PPA Adjustment	54,376	127,228	277,557	313,482	772,643
Total Fuel Costs (F)	$ 108,842,190	$ 128,802,140	$ 183,597,995	$ 91,608,553	$ 512,850,878
Sales (S) (MWh)	3,223,816	2,595,687	3,400,724	2,150,458	11,370,685
Cost Per Unit (F/S) ($/kWh)	$0.03376	$0.04962	$0.05399	$0.04260	$0.04510

Source: Attachment DJ-3

Q HOW DID AESI ESTIMATE THE FAC COST IMPACT IF THE EAGLE VALLEY OUTAGE DID NOT OCCUR – NON-OUTAGE SCENARIO?

A AESI witness David Jackson on Attachment DJ-3 estimated the Company's fuel and purchased power cost assuming Eagle Valley had been available during the outage period (Non-Outage Scenario). As shown on Table 5 below, the estimated FAC Cost in the Non-Outage Scenario is approximately $470.28 million ($41.36/MWh).

TABLE 5

Company Projected Non-Outage FAC Costs

Description	FAC 133	FAC 134	FAC 135	FAC 136	Total
Coal and Oil Generation	$ 43,683,815	$ 44,079,643	$ 42,747,421	$38,788,611	$169,299,490
Other Generation - Internal Combustion	5,347	3,237	6,166	4,065	18,815
Natural Gas Generation	44,940,774	74,269,133	101,628,689	48,520,675	269,359,272
Financial Hedges Gains/Losses & Transactional Fees	-	-	-	-	-
Purchases through MISO					
Wind Purchase Power Agreement Purchases	10,253,574	12,960,067	23,575,450	14,894,202	61,683,293
Non-Wind PPA Market Purchases	5,561,669	3,764,187	2,643,532	1,382,302	13,351,691
Other	4,841	4,993	7,482	13,825	31,141
MISO Components of Cost of Fuel	3,150,352	6,755,564	11,144,778	(3,664,531)	17,386,163
Purchased Power other than MISO	7,707,074	6,708,000	3,424,862	3,190,647	21,030,583
LESS:					
Inter-System Sales through MISO	$ 12,122,836	$ 22,218,601	$ 23,469,946	$15,365,866	$ 73,177,250
Transmission Losses	748,954	1,034,797	1,055,954	923,665	3,763,370
Lakefield PPA Adjustment	482,066	1,011,188	2,417,874	1,030,477	4,941,606
Total Fuel Costs	$101,953,590	$124,280,238	$158,234,607	$85,809,787	$470,278,221
Sales (S) (MWh)	3,223,816	2,595,687	3,400,724	2,150,458	11,370,685
Cost Per Unit (F/S) ($/kWh)	$0.03163	$0.04788	$0.04653	$0.03990	$0.04136

Source: Attachment DJ-3

Q HOW DID AESI ESTIMATE THE IMPACT ON FAC (133-136) COST CAUSED BY THE EAGLE VALLEY OUTAGE?

A The Company's FAC costs under actual conditions of $512.85 million, less its estimated cost had Eagle Valley been operating of $470.28 million, indicate an increase in FAC costs of approximately $42.57 million. From this balance, AESI proposes to reduce the balance by its incremental cost of fuel by $1.05 million., which produces the Company's estimated increased FAC recoverable costs of $41.52 million. The Company also includes the financial hedge gains and losses of $8.18 million in its Non-Outage Scenario, which reduced the Eagle Valley Impact. The specific detail underlying the Company's projections under actual versus its forecasted costs with Eagle Valley operating are summarized below in Table 6.

TABLE 6

Company Projected Eagle Valley FAC Impact

Description	FAC 133	FAC 134	FAC 135	FAC 136	Total
Coal and Oil Generation	$ -	$ -	$ -	$ -	$ -
Other Generation - Internal Combustion	-	-	-	-	-
Natural Gas Generation	22,782,168	37,597,686	41,346,942	19,346,334	121,073,131
Financial Hedges Gains/Losses & Transactional Fees	1,590,974	5,635,472	(482,546)	-	6,743,900
Purchases through MISO	-	-			-
Wind Purchase Power Agreement Purchases	-	-	-	-	-
Non-Wind PPA Market Purchases	(18,855,069)	(26,004,430)	(42,021,679)	(13,293,108)	(100,174,285)
Other	-	-	-	-	-
MISO Components of Cost of Fuel	-	-	-	-	-
Purchased Power other than MISO	-	-	-	-	-
LESS:					
Inter-System Sales through MISO	$ 11,387,236	$ 20,122,556	$ 21,262,879	$ 10,602,243	$ 63,374,915
Transmission Losses	591,747	744,114	802,910	532,753	2,671,524
Lakefield PPA Adjustment	427,690	883,960	2,140,317	716,995	4,168,963
Total Adjustments	$ (6,888,600)	$ (4,521,902)	$ (25,363,388)	$ (5,798,766)	$ (42,572,657)
Incremental Cost of Fuel	$ 237,866	$ (403,257)	$ 1,770,902	$ (551,330)	$ 1,054,182
FAC Impact	$ (6,650,735)	$ (4,925,159)	$ (23,592,486)	$ (6,350,096)	$ (41,518,476)

Source: Attachment DJ-3

Q DO YOU AGREE WITH AESI'S ESTIMATE OF THE IMPACT OF THE EAGLE VALLEY OUTAGE FOR FAC 133 THROUGH FAC 136?

A I do not agree. The concern I have with the Company's estimate is that it is substantially understated for the following reasons:

1. It hasn't justified why the financial hedge cost of $8.18 million should be attributable to cost related to returning Eagle Valley to service.

2. The primary drivers include the expected increased natural gas generation costs, relative to the output of Eagle Valley, the reduction in non-wind market purchases, and the increase in Off-System Sales margins or inter-system sales through MISO. For the reasons outlined above, the projections for natural gas and MISO purchases are reasonable, however the Company's estimated impact significantly understates the amount of Off-System Sales margins available had Eagle Valley been operated.

Specifically, for natural gas generation, the Company estimates an increase in natural gas of $121.07 million. This equates 4,321,751 MWh estimated for Eagle Valley had it operated and equates a dispatch cost of Eagle Valley averaging around $28 per MWh. This estimate aligns with the Company's projected dispatch costs for Eagle Valley on average over the four FAC periods.

Similarly, the Company's projected reduction in MISO non-wind purchased power costs of $100.17 million aligns with its estimated reduction in MWhs purchased from MISO at 2,010,155. This implies a market purchase price avoidance from MISO of approximately $49.83 per MWh. Again, this reasonably aligns with the Company's other cost estimates.

However, and significantly, the Company has understated the amount of Off-System Sales margins produced through inter-system sales through MISO. Specifically, in Table 6 above, AESI's estimate implies approximately $63.37 million sales margin revenues to be credited against FAC under its two options, but this number is considerably lower than that reflected in its dispatch costs. Specifically, in response to IG DR 8.1, the Company indicated increased MISO sales of approximately **[redacted]**. This reasonably aligns with the MISO purchases. However, as shown above in Table 6, under its impact analysis due to the loss of Eagle Valley, the Company has estimated MISO sales revenues of **[redacted]**. That in combination with the Company's production cost sales estimate of **[redacted]** equates to a MISO sales price of $27.18 per MWh. This is significantly lower than the actual MISO sales price during the period.

A comparison of the Off-System Sales margins implicit in the Company's response to IG DR 8-1, and that reflected in its estimated impact of Eagle Valley is summarized in Table 7 below.

TABLE 7

Comparison of MISO Sales - Actual vs Non-Outage Scenario

	IG DR 8-1 Confidential Attachment 1			Attachment DJ-3			
	Actual MISO Sales	Non-Outage MISO Sales	Eagle Valley Impact	Actual MISO Sales	Non-Outage MISO Sales	Eagle Valley Impact	Difference
May-21	** [redacted] **	** [redacted] **	** [redacted] **	$ 46,933	$ 3,572,542	$ 3,525,609	$ 2,413,032
Jun-21	** [redacted] **	** [redacted] **	** [redacted] **	292,850	3,810,447	3,517,597	3,319,247
Jul-21	** [redacted] **	** [redacted] **	** [redacted] **	395,817	4,739,848	4,344,031	3,608,176
Aug-21	** [redacted] **	** [redacted] **	** [redacted] **	1,055,312	7,899,208	6,843,896	6,610,781
Sep-21	** [redacted] **	** [redacted] **	** [redacted] **	141,081	5,552,280	5,411,199	4,128,109
Oct-21	** [redacted] **	** [redacted] **	** [redacted] **	899,652	8,767,113	7,867,461	5,521,725
Nov-21	** [redacted] **	** [redacted] **	** [redacted] **	-	3,544,069	3,544,069	1,498,424
Dec-21	** [redacted] **	** [redacted] **	** [redacted] **	56,393	7,679,564	7,348,268	4,520,037
Jan-22	** [redacted] **	** [redacted] **	** [redacted] **	66,608	12,246,313	10,370,542	9,005,416
Feb-22	** [redacted] **	** [redacted] **	** [redacted] **	555,647	8,846,000	8,290,353	6,137,059
Mar-22	** [redacted] **	** [redacted] **	** [redacted] **	4,207,976	6,519,866	2,311,890	1,666,592
TOTAL	$ 16,740,064	$ 128,543,578	$ 111,803,514	$ 7,718,269	$ 73,177,250	$ 63,374,915	$ 48,428,599

As outlined above, the Company's detailed assessment of the Off-System Sales available if the Eagle Valley outage had not occurred would have been over $111.8 million of FAC offsets. However, Mr. Jackson's estimated impact from Eagle Valley only assumes approximately $63.4 million of Off-System Sales margins. Hence, this significant discrepancy, $48.4 million, in Off-System Sales available attributable to the Eagle Valley outage not occurring, explains the difference between my estimated FAC cost impact due to the Eagle Valley outage compared to that of Mr. Jackson.

Q DO YOU BELIEVE MR. JACKSON'S ESTIMATED INCREASE IN FAC COSTS DUE TO THE EAGLE VALLEY OUTAGE IS REASONABLE?

A No. As outlined above, he significantly understated the additional sales in Off-System Sales margin that can reduce recoverable FAC costs. Hence, he has materially understated the FAC cost damages caused by the extended forced outage at Eagle Valley.

VI. CONCLUSION

Q WHAT IS YOUR RECOMMENDATION?

A I recommend that the Commission order AESI to provide a refund to ratepayers, with accrued interest, in the subsequent FAC proceedings, in the amount of $70.9 million reflecting FAC savings to AESI had the Eagle Valley forced outage during FAC 133 through 136 not occurred. The forced outage for Eagle Valley during these periods was due to the utility's own imprudent and negligent acts, and the resulting replacement FAC costs should not be recovered from customers. Interest should be awarded to ratepayers for not only any delay in that refund, but also because AESI underestimated the impact of the outages, thus imposing costs on customers in FAC 133-136 which should not have been recovered from ratepayers.

Q DOES THIS CONCLUDE YOUR TESTIMONY?

A Yes.

Qualifications of Michael P. Gorman

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Michael P. Gorman. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and a Managing Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A In 1983 I received a Bachelor of Science Degree in Electrical Engineering from Southern Illinois University, and in 1986, I received a Master's Degree in Business Administration with a concentration in Finance from the University of Illinois at Springfield. I have also completed several graduate level economics courses.

In August of 1983, I accepted an analyst position with the Illinois Commerce Commission ("ICC"). In this position, I performed a variety of analyses for both formal and informal investigations before the ICC, including: marginal cost of energy, central dispatch, avoided cost of energy, annual system production costs, and working capital. In October of 1986, I was promoted to the position of Senior Analyst. In this position, I assumed the additional responsibilities of technical leader on projects, and my areas of responsibility were expanded to include utility financial modeling and financial analyses.

In 1987, I was promoted to Director of the Financial Analysis Department. In this position, I was responsible for all financial analyses conducted by the Staff. Among other things, I conducted analyses and sponsored testimony before the ICC on rate of return, financial integrity, financial modeling and related issues. I also supervised the development of all Staff analyses and testimony on these same issues. In addition, I supervised the Staff's review and recommendations to the Commission concerning utility plans to issue debt and equity securities.

In August of 1989, I accepted a position with Merrill-Lynch as a financial consultant. After receiving all required securities licenses, I worked with individual investors and small businesses in evaluating and selecting investments suitable to their requirements.

In September of 1990, I accepted a position with Drazen-Brubaker & Associates, Inc. ("DBA"). In April 1995, the firm of Brubaker & Associates, Inc. was formed. It includes most of the former DBA principals and Staff. Since 1990, I have performed various analyses and sponsored testimony on cost of capital, cost/benefits of utility mergers and acquisitions, utility reorganizations, level of operating expenses and rate base, cost of service studies, and analyses relating to industrial jobs and economic development. I also participated in a study used to revise the financial policy for the municipal utility in Kansas City, Kansas.

At BAI, I also have extensive experience working with large energy users to distribute and critically evaluate responses to requests for proposals ("RFPs") for electric, steam, and gas energy supply from competitive energy suppliers. These analyses include the evaluation of gas supply and delivery charges, cogeneration and/or combined cycle unit feasibility studies, and the evaluation of third-party asset/supply management agreements. I have participated in rate cases on rate design and class cost of service for electric, natural gas, water and wastewater utilities. I have also analyzed commodity pricing indices and forward pricing methods for third party supply agreements, and have also conducted regional electric market price forecasts.

In addition to our main office in St. Louis, the firm also has branch offices in Corpus Christi, Texas; Detroit, Michigan; Louisville, Kentucky and Phoenix, Arizona.

Q HAVE YOU EVER TESTIFIED BEFORE A REGULATORY BODY?

A Yes. I have sponsored testimony on cost of capital, revenue requirements, cost of service and other issues before the Federal Energy Regulatory Commission and numerous state regulatory commissions including: Alaska, Arkansas, Arizona, California, Colorado, Delaware, the District of Columbia, Florida, Georgia, Idaho, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, Montana, Nevada, New Hampshire, New Jersey, New Mexico, New York, North Carolina, North Dakota, Ohio, Oklahoma, Oregon, South Carolina, South Dakota, Tennessee, Texas, Utah, Vermont, Virginia, Washington, West Virginia, Wisconsin, Wyoming, and before the provincial regulatory boards in Alberta, Nova Scotia, and Quebec, Canada. I have also sponsored testimony before the Board of Public Utilities in Kansas City, Kansas; presented rate setting position reports to the regulatory board of the municipal utility in Austin, Texas, and Salt River Project, Arizona, on behalf of industrial customers; and negotiated rate disputes for industrial customers of the Municipal Electric Authority of Georgia in the LaGrange, Georgia district.

Q PLEASE DESCRIBE ANY PROFESSIONAL REGISTRATIONS OR ORGANIZATIONS TO WHICH YOU BELONG.

A I earned the designation of Chartered Financial Analyst ("CFA") from the CFA Institute. The CFA charter was awarded after successfully completing three examinations which covered the subject areas of financial accounting, economics, fixed income and equity valuation and professional and ethical conduct. I am a member of the CFA Institute's Financial Analyst Society.

445076

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

SUBDOCKET FOR REVIEW OF INDIANAPOLIS POWER & LIGHT COMPANY D/B/A AES INDIANA'S 2021 EXTENDED FORCED OUTAGE AT EAGLE VALLEY AND ITS RELATED IMPACT ON FUEL PROCUREMENT AND FUEL COSTS	**)**	**CAUSE NO. 38703-FAC133 S1**

Verification

I, Michael P. Gorman, a Managing Principal of Brubaker & Associates, Inc., affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

Michael P. Gorman

August 29, 2022

Cause No. 38703 FAC 133 S1
AESI's Responses to Data Requests
Referenced in the Verified Direct Testimony and Attachments
of AESI Industrial Group Witness Michael P. Gorman

AESI's Responses to Data Requests **Pages**

IG 4-1 and Confidential Attachment..2-3

IG 4-2..4

IG 4-3 and Confidential Attachment..5-6

IG 6-2..7

IG 7-1 and Confidential Attachment..8-9

IG 8-1 and Confidential Attachment..10-11

Data Request IG DR 4 - 1

Please provide the following information with regard to every cold start event prior to Incident 1A at Eagle Valley.

a. Start time.
b. Total event duration.
c. Identify the turbine being utilized for startup for each event.
d. HP Exhaust temperature (F) by minute.
e. Turbine speed (rpm) by minute.
f. STG Synch time.
g. HP steam pressure (psi).

Objection:
AES Indiana objects to the Request on the grounds and to the extent the Request solicits information that is confidential, proprietary, competitively sensitive, trade secret and/or Critical Energy Infrastructure Information ("CEII"). Subject to and without waiver of the foregoing objections, AES Indiana provides the following response with the confidential information provided pursuant to the nondisclosure agreement between the parties.

Response:
IG DR 4-1 Confidential Attachment 1 includes the cold starts during commissioning and the cold starts after commercial operation date prior to Incident 1A.

Also included in the data is the HP Steam Throttle Pressure (psig), Main Steam Temperature (°F), HP Turbine Exhaust Temp High (1 indicates the alarm is active, 0 indicates the alarm is inactive), CT 1 Load MW, CT 2 Load MW, and Gen Watts (STG load in MW).

The total event duration is defined as the difference between starting the STG and the STG reaching 40MW. 40MW is when startup is complete for the STG.

SUPPLEMENTAL RESPONSE:
The summary tab on IG DR 4-1 Confidential Attachment 1 (column H) has a typo on line 11 (Startup on 2/22/2020). As shown on the tab in this attachment for 3-22-2020 column I, GT 1 was used utilized for this startup.

The confidential attachment to IG 4-1 is redacted in its entirety

Data Request IG DR 4 - 2

Please explain if Eagle Valley was ever tripped or shut down manually during a cold start event. If so, please provide the date of the event and provide explanation of the cause of the shutdown and any corrective actions taken.

Objection:
AES Indiana objects to the Request on the grounds and to the extent the Request solicits information that is confidential, proprietary, competitively sensitive, trade secret and/or Critical Energy Infrastructure Information ("CEII"). Subject to and without waiver of the foregoing objections, AES Indiana provides the following response with the confidential information provided pursuant to the nondisclosure agreement between the parties.

Response:
The information is included in IG DR 4-1 Confidential Attachment 1, Column D ("Trip or Shut Down?") and Column E ("Cause").

After commercial operation date, the STG was shut down manually during one of the five cold startups. In the data provided, it can be seen the HP Turbine Exhaust Temp High alarm activated in four of the five cold startups, with the exception being the 8/16/2020 startup. During the 8/16/2020 startup, GT-2 was unable to increase load which caused low HP Steam Temperature and Pressure and the IP Bypass Valve was stuck fully open. These issues would not allow the STG to increase its load. The STG and GT-2 were shut down manually, the issues were corrected, and it was restarted on 8/17/2020 for a hot start.

Data Request IG DR 4 - 3

Please provide the date and duration of every forced outage at Eagle Valley prior to Incident IA and provide an explanation of the cause of the outage and any corrective actions taken as a result of the forced outage.

Objection:
AES Indiana objects to the Request on the grounds and to the extent the Request solicits information that is confidential, proprietary, competitively sensitive, trade secret and/or Critical Energy Infrastructure Information ("CEII"). Subject to and without waiver of the foregoing objections, AES Indiana provides the following response with the confidential information provided pursuant to the nondisclosure agreement between the parties.

Response:
AES Indiana interprets "forced outage at Eagle Valley" to mean full forced outage of the CCGT plant.

IG DR 4-3 Confidential Attachment 1 includes the list of all the forced outages, causes, and the corrective actions.

**The confidential attachment to IG 4-3
is redacted in its entirety**

Data Request IG DR 6 - 2

Please refer to IG DR 4-1 Confidential Attachment 1 and IG DR 4-2. Please explain what corrective actions were taken to resolve the issues with Gas Turbine-2 not increasing load and the IP Bypass valve being fully stuck open during the cold start event on 8/16/2020-8/17/2020.

Objection:
AES Indiana objects to the Request on the grounds and to the extent the request solicits information that exceeds the scope of this proceeding and is not reasonably calculated to lead to the discovery of relevant or admissible evidence. Subject to and without waiver of the foregoing objections, AES Indiana provides the following response.

Response:

To resolve Gas Turbine 2 not increasing load it was found that the temperature matching mode was latched on and even after the operator pressed the button to turn off temperature matching mode it would not turn off. Gas Turbine 2 was shut down, and while it was shutting down the temperature matching mode permissive became false. This turned off temperature matching mode.

To resolve the IP Bypass valve being fully stuck open, the valve positioner had failed. The valve positioner was replaced.

Data Request IG DR 7 - 1

Please refer to AES Indiana Attachment DJ-3 sponsored by Company Witness David Jackson. For each month of the Eagle Valley outage, please provide the following information broken out for each Company-owned resource, and/or purchased power agreement capacity under both the actual and non-outage scenarios:

a. Fuel Cost by Fuel Type,
b. Fuel Burned by Fuel Type,
c. Net Generation,
d. Variable Operating and Maintenance Expense,
e. Dispatch Cost,
f. Operating Capacity,
g. Capacity Factor,
h. Outage Status,
i. Outage Type if applicable (forced, planned, maintenance, etc.), and
j. Monthly Load Factor of Resource.

Objection:

AES Indiana objects to the Request on the grounds and to the extent the request seeks information that is confidential, proprietary, competitively-sensitive and/or trade secret. Subject to and without waiver of the foregoing objections, AES Indiana provides the following response.

Response:

a. – g. and j. See IG DR 7-1 Confidential Attachment 1.
h. – i. See IG DR 7-1 Confidential Attachments 2 through 12.

**The confidential attachment to IG 7-1
is redacted in its entirety**

Data Request IG DR 8 - 1

Please refer to AES Indiana Attachment DJ-3 sponsored by Company Witness David Jackson. For every month of the Eagle Valley outage, please provide the following information for both the Actual and Non-Outage Scenario and the On-Peak, Off-Peak and ATC ("Around the Clock") Periods:

a. MISO Market Purchases (MWh),
b. MISO Market Purchases ($/MWh),
c. MISO Market Purchases ($),
d. MISO Market Sales (MWh),
e. MISO Market Sales ($/MWh),
f. MISO Market Sales ($).

Objection:
AES Indiana objects to the Request on the grounds and to the extent the Request solicits information that is confidential, proprietary, competitively sensitive and/or trade secret. AES Indiana objects to the Request on the grounds and to the extent the request seeks a compilation, analysis or study that AES Indiana has not performed and to which AES Indiana objects to performing. AES Indiana objects to the Request on the grounds and to the extent it is overly broad and unduly burdensome. Subject to and without waiver of the foregoing objections, AES Indiana provides the following response with the confidential information provided pursuant to the nondisclosure agreement between the parties.

Response:
See IG DR 8-1 Confidential Attachment 1 for the ATC by month for the Actual and Non-Outage Scenarios. The On-Peak and Off-Peak data for the Non-Outage scenario is not available. The On-Peak and Off-Peak data for the Actual scenario has not been compiled and it would be unduly burdensome and unnecessary to do so.

The confidential attachment to IG 8-1 is redacted in its entirety

AES Indiana

Eagle Valley Cost

Line	Date	Eagle Valley Non-Outage Generation[1]	Eagle Valley Dispatch Cost ($/MWh)[2]	Eagle Valley FAC Expense	MISO Market Purchase Price ($/MWh)[3]	MISO Sales Price ($/MWh)[3]	Offsetting Actual MISO Market Purchases (MWh)	Remaining Generation for MISO Energy Sales (MWh)	Total Eagle Valley Savings	Cost
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	May-21	** [redacted] **	** [redacted] **	** [redacted] **	** [redacted] **	** [redacted] **	** [redacted] **	** [redacted] **	$9,315,058	$1,754,829
2	Jun-21	** [redacted] **	** [redacted] **	** [redacted] **	** [redacted] **	** [redacted] **	** [redacted] **	** [redacted] **	$11,135,310	$3,346,074
3	Jul-21	** [redacted] **	** [redacted] **	** [redacted] **	** [redacted] **	** [redacted] **	** [redacted] **	** [redacted] **	$12,658,890	$3,429,068
4	Aug-21	** [redacted] **	** [redacted] **	** [redacted] **	** [redacted] **	** [redacted] **	** [redacted] **	** [redacted] **	$15,888,513	$5,321,180
5	Sep-21	** [redacted] **	** [redacted] **	** [redacted] **	** [redacted] **	** [redacted] **	** [redacted] **	** [redacted] **	$13,636,443	$2,375,672
6	Oct-21	** [redacted] **	** [redacted] **	** [redacted] **	** [redacted] **	** [redacted] **	** [redacted] **	** [redacted] **	$28,533,155	$10,739,861
7	Nov-21	** [redacted] **	** [redacted] **	** [redacted] **	** [redacted] **	** [redacted] **	** [redacted] **	** [redacted] **	$27,274,313	$10,793,684
8	Dec-21	** [redacted] **	** [redacted] **	** [redacted] **	** [redacted] **	** [redacted] **	** [redacted] **	** [redacted] **	$19,553,295	$6,986,964
9	Jan-22	** [redacted] **	** [redacted] **	** [redacted] **	** [redacted] **	** [redacted] **	** [redacted] **	** [redacted] **	$29,510,144	$14,738,663
10	Feb-22	** [redacted] **	** [redacted] **	** [redacted] **	** [redacted] **	** [redacted] **	** [redacted] **	** [redacted] **	$21,339,563	$6,847,722
11	Mar-22	** [redacted] **	** [redacted] **	** [redacted] **	** [redacted] **	** [redacted] **	** [redacted] **	** [redacted] **	$10,496,798	$4,537,109
12	TOTAL	4,321,751		$128,470,657			2,010,155	2,311,596	$199,341,482	**$70,870,826**

Sources:

[1] IG DR 4-6

[2] Confidential Attachment IG DR 7-1

[3] Confidential Attachment IG DR 8-1