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INDIANA UTILITY
REGULATORY COMMISSION

VERIFIED DIRECT TESTIMONY

OF

CALEB STEINER

ON BEHALF OF

INDIANAPOLIS POWER & LIGHT COMPANY

D/B/A AES INDIANA

Cause No. 46258

VERIFIED DIRECT TESTIMONY OF CALEB STEINER

ON BEHALF OF AES INDIANA

1. INTRODUCTION

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

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

Q2. What is your position with AES Services?

A2. I am Director, Regulated Operations and Term Management, US Utilities.

Q3. On whose behalf are you submitting this direct testimony?

A3. I am submitting this testimony on behalf of AES Indiana.

Q4. Please describe your duties as Director, Regulated Operations and Term Management, US Utilities.

A4. As the Director, Regulated Operations and Term Management, US Utilities, I am responsible for managing the relevant data and analytics associated with AES Indiana's portfolio of generation, fuel, load, hedges, and related commodities. This includes the ongoing daily, weekly, and monthly market reporting and analysis to support trading activities in power, fuel, emission, and Renewable Energy Credits ("RECs"). A portion of my role involves analysis of Midcontinent Independent System Operator ("MISO"), legislative, and regulatory developments with regards to expected portfolio generation including off system sales.

Q5. Please summarize your education and professional qualifications.

A5. I received a Bachelor of Arts from Washington and Lee University, a Master of Public Administration in Policy Analysis, and a Master of Science in Finance both from Indiana University.

Q6. Please summarize your prior work experience.

A6. I have been employed by AES Services since 2021. Prior to AES Services, I worked at Hoosier Energy from 2009 to 2021 in various roles including renewable energy development, finance, risk management, and commodity hedging.

Q7. Have you testified previously before the Indiana Utility Regulatory Commission ("Commission") or any other regulatory agency?

A7. Yes. I testified in AES Indiana's most recent rate case, Cause No. 45911. I also provided testimony in Cause Nos. 44795 OSS-8 and OSS-9.

Q8. What is the purpose of your testimony in this proceeding?

A8. My testimony provides an overview of the EnCompass generation dispatch model that informs the Unadjusted and Adjusted Test Years' forecasted generation, generation fuel costs, generation production costs and purchased power costs. My testimony supports the Company's proposal to maintain the structure of the Off-System Sales ("OSS") Margin Adjustment Rider 25 and the Capacity Adjustment Rider 24 in their current form with an update to the benchmarks embedded in base rates. I also provide updated benchmarks for environmental consumables/commodities and NOx emission allowance purchases/sales in

AES Indiana's existing Environmental Compliance Cost Recovery Adjustment ("ECCRA") Rider 20.

Q9. Are you sponsoring or co-sponsoring any financial exhibits or attachments?

A9. Yes. I sponsor or co-sponsor the following financial exhibit schedules:

- AES Indiana Financial Exhibit AESI-OPER, Schedule REV6 – Summary of Off-System Sales ("OSS")
- AES Indiana Financial Exhibit AESI-OPER, Schedule REV9 – Capacity Sales
- AES Indiana Financial Exhibit AESI-OPER, Schedule OM3 – Capacity Costs
- AES Indiana Financial Exhibit AESI-OPER, Schedule OM4 – Off-System Sales Power Production Costs
- AES Indiana Financial Exhibit AESI-OPER, Schedule OM5 – Generation Consumables Variable Expenses
- AES Indiana Financial Exhibit AESI-OPER, Schedule OM8 – Seasonal NOx Emissions Allowance Expense

Q10. Did you submit any workpapers?

A10. Yes. AES Indiana is submitting workpapers in electronic format that support the basic rate case schedules. I am sponsoring the workpapers that support the financial statements and schedules that I sponsor.

Q11. Were these exhibits, attachments, or workpapers, or portions thereof, that you are sponsoring or co-sponsoring prepared or assembled by you or under your direction and supervision?

A11. Yes.

Q12. For ease of reference, please summarize the key terms utilized in the Company's filing.

A12. Key terms as defined by AES Indiana witness Peters include the following.[1] First, the per books twelve months ended December 31, 2024 is the "Historical Base Period". Second, the forecasted twelve months ending December 31, 2025 is the "Linking Period". Next, the unadjusted forward-looking test year for twelve months ending December 31, 2026 is the "Unadjusted Test Year". Finally, the adjusted forward-looking test year for the twelve months ending December 31, 2026 is the "Adjusted Test Year".

2. ENCOMPASS DISPATCH MODEL

Q13. Please provide an overview of the EnCompass dispatch model.

A13. The EnCompass dispatch model runs a detailed simulation of AES Indiana's system against a retail load forecast, expected generation performance, and forecasted commodity prices. The key inputs to the model are forecasted retail load, generator capacity ratings, generator fuel costs and the market price for power. The same model is used to prepare the Company's fuel cost adjustment ("FAC") forecasts.

Q14. What are the primary inputs to the EnCompass model and their sources?

A14. The retail load forecast is the weather normalized 2026 forecasted test year sales presented by AES Indiana witness Russo. The generator capacity ratings and performance profiles are consistent with those used for FAC forecasts. Scheduled maintenance outages are also included for AES Indiana thermal assets. The forward power and gas prices for the 2026

[1] AES Indiana witness Peters, Q/A 13.

Unadjusted Test Year are dated October 17, 2024. The dispatch prepared for the Adjusted Test Year utilized the same model parameters as the Unadjusted Test Year except that: 1) Petersburg Units 3 & 4 were modeled as converted gas units available for all of 2026; and 2) updated forward prices were used as discussed below.

Q15. What forward prices were used for purposes of the Adjusted Test Year dispatch model?

A15. The price forecast for monthly gas prices and monthly power prices used in the Adjusted Test Year dispatch were provided by AES Indiana witness Dickerson and represent an average settled forward price for each month derived from every settlement day of 2024. Mr. Dickerson's testimony explains the reasonableness of this approach.

Q16. What are the primary outputs of the EnCompass model?

A16. The outputs of the EnCompass model provide values for MWh generation, generator fuel, and production costs and revenues. The model compares the MWh generation to the retail load forecast to estimate the timing, quantity, and value of both purchased power and off system sales. I provided the outputs of the Adjusted Test Year dispatch model to other AES Indiana witnesses, including AES Indiana witness Dickerson. The following financial schedules use outputs from the EnCompass model:

- AES Indiana Financial Exhibit AESI-OPER, Schedule REV6 – Summary of Off-System Sales
- AES Indiana Financial Exhibit AESI-OPER, Schedule OM2 – Cost of Fuel and Purchased Power (sponsored by witness Dickerson)

- AES Indiana Financial Exhibit AESI-OPER, Schedule OM4 – Off-System Sales Power Production Costs
- AES Indiana Financial Exhibit AESI-OPER, Schedule OM5 – Generation Consumables Variable Expenses
- AES Indiana Financial Exhibit AESI-OPER, Schedule OM8 – Seasonal NOx Emissions Allowance Expense

3. OSS MARGINS

Q17. Please describe an OSS.

A17. An OSS reflects the sale of power when the amount of AES Indiana generation for an hour exceeds the amount of system power consumed by its retail customers. AES Indiana generation is the sum of the power produced by AES Indiana-owned generation and the power produced by the Lakefield Wind Project.[2] The amount of system power consumed by AES Indiana's retail customers is the amount of AES Indiana-owned generation plus the net flow through of all of the AES Indiana control area tie-lines less transmission losses (as determined by MISO).

Q18. What are OSS margins?

A18. The margin from OSS is the difference between the revenue from OSS and the sum of fuel and production costs from the unit(s) involved in the sale. For an hourly OSS, the AES Indiana generating units are sorted by highest fuel and production costs to lowest fuel and production costs, which establishes a "stack" of units for that hour. The OSS volumes are allocated to the highest cost unit first and then down the stack, based on each unit's

[2] See AES Indiana witness Ellis' Attachment GE-1.

incremental generation, until the OSS volumes are satisfied. The Locational Marginal Price at each resulting generator is then multiplied by its generation and summed up to realize the OSS revenue. The incremental fuel and production costs from the same group of units is calculated and subtracted from the OSS revenue to calculate the OSS margin.

Q19. Does the Company propose to continue providing 100% of OSS margin to retail customers?

A19. Yes. Per the Commission's Orders in Cause Nos. 45029 and 45911, 100% of the Company's OSS margins currently flow through rates (via Rider 25) to the benefit of retail customers. The Company proposes to maintain this structure with an updated benchmark embedded in the retail revenue requirement. This proposal reasonably allows the Company's basic rates to reflect the cost of providing retail service in the competitive wholesale markets and efforts in the competitive wholesale market to mitigate the overall customer bill.

Q20. What OSS margin benchmark does the Company propose in this case?

A20. AES Indiana proposes setting the benchmark at $24.9 million as shown on <u>AES Indiana Financial Exhibit AESI-OPER, Schedule REV6</u>, line 5. This is a decrease of $3.7 million from the $28.6 million benchmark embedded via the Settlement Agreement approved in Cause No. 45911. The Company proposes to continue to reconcile actual OSS margins annually in the existing Rider 25. The proposed benchmark is based on the Adjusted Test Year EnCompass model outputs described above.

Q21. How does the proposed level of OSS margins embedded in the Adjusted Test Year revenue requirement compare to OSS margins during the Historical Base Period?

A21. The proposed OSS margins are reasonable when viewed against the Historical Base Period, Linking Period, and Unadjusted Test Year. These values are listed in Table CS-1 below. The Historical Base Period and Linking Period illustrate the volatility of OSS margins from year to year.

Table CS-1: OSS Margins, 2024-2026

Year	Period	OSS Margin ($000)
2024	Base Historical Period	$ 4,389
2025	Linking Period	$ 44,663
2026	Unadjusted Test Year	$ 18,082
2026	Adjusted Test Year	$ 24,906

Q22. Please discuss the differences in OSS margins from the Historical Base Period through the Adjusted Test Year.

A22. Several variables created an environment for low OSS margins in the Base Historical Period. First, the winter weather in January and February 2024 was warmer than the 30-year average. The result of warm weather in the winter of 2024 reduced demand, which in turn resulted in lower power prices. In addition, the lower power demand reduced the expected natural gas consumption for power generation; this in turn allowed more gas to remain in storage during this period, which lowered spot gas prices not only in the winter but through the summer and fall of 2024. The result of lower power and gas prices created a low margin environment for thermal assets, including Petersburg Generating Station. This is reflected in the 2024 OSS margin. The Linking Period reflects expectations of higher gas and power prices that improve the expected generation and margins from Petersburg and Eagle Valley Generating Stations. The Unadjusted Test Year is lower than the Adjusted Test Year because the Unadjusted Test Year reflects current planned outages, whereas the Adjusted Test Year assumes the availability of the Petersburg Generating Station for the entire year of 2026. The proposed embedded Adjusted Test Year OSS margins of $24.9 million is based on a reasonable forecast of the Company's generation fleet performance in the market, recognizing that OSS margins remain volatile, significant, and largely outside of AES Indiana's control.

Q23. Is the Company's proposal reasonable?

A23. Yes. Retail rates for electric service are necessarily underpinned by the cost of providing retail service. OSS margins are produced via the competitive wholesale market and are used in the ratemaking process to reduce the cost of retail service. The Company's proposal to continue to share 100% of the OSS margins with customers above and below the embedded amount is reasonable.

4. CAPACITY CHARGES AND CREDITS

Q24. How are charges/credits for capacity generated?

A24. As a Load Serving Entity in MISO, AES Indiana is obligated to have sufficient capacity resources to cover its forecasted peak demand plus its Planning Reserve Margin ("PRM") or acquire additional capacity through bilateral transactions with other market participants or by bidding on capacity in MISO's annual Planning Resource Auction ("PRA"). If AES Indiana is obligated to acquire additional capacity through bilateral transactions with other market participants or through the PRA, the cost is flowed through Rider 24. If AES Indiana has more than enough capacity resources to cover its forecasted peak demand and PRM, AES Indiana may sell capacity through bilateral transactions with other market participants, or may offer capacity in MISO's PRA, which generates a reduction in the cost of service for customers via Rider 24.

Q25. What is the impact of the current MISO capacity construct on the Company's forecasted capacity position?

A25. The seasonal construct and the accreditation methodology change the capacity position expectations for the Company annually. Specifically, MISO requires the Company to manage four distinct seasons in a year, each with their own Planning Reserve Margin Requirement ("PRMR"). The PRMR changes annually based on MISO findings in the Loss of Load Expectation ("LOLE") study. Therefore, the total Resource Adequacy Requirement ("RAR") for the Company moves incrementally up or down each year. Furthermore, the amount of Seasonal Accredited Capacity ("SAC") that each thermal generator is awarded varies by historical performance. The SAC values from generators are used to offset the Company's RAR. The annual changes in RAR and SAC contribute to volatility in the overall capacity position of the Company each year.

Q26. How does the Company propose to recover charges/credits for capacity?

A26. AES Indiana proposes to continue to recognize incremental changes in the charges and credits for the net cost and benefit of AES Indiana's participation in MISO's Resource Adequacy Process and the cost and benefit of bilateral capacity transactions by maintaining the Company's existing Capacity Adjustment ("CAP") Rider.[3]

Q27. What is the Adjusted Test Year level of capacity costs and revenues?

A27. The forecasted level of capacity costs in the Adjusted Test Year is $2.9 million and is shown in AES Indiana Financial Exhibit AESI-OPER, Schedule OM3, line 1. The forecasted level of capacity revenue is $8.9 million and is shown in AES Indiana Financial

[3] See also AES Indiana witness Aliff Q/A 41.

Exhibit AESI-OPER, Schedule REV9, line 3. The forecasted position was derived by carrying forward the RAR and SAC from the 2025-2026 PRA to planning year 2026-2027 and using an auction clearing price in the PRA used in the 2025 OSS filing. Table CS-2 below illustrates the changes in net capacity revenue and expense for the various periods considered in this filing.

Table CS-2: Net Capacity Revenue, 2024-2026

Year	Period	Net Capacity Revenue (Expense) ($000)	
2024	Historical Base Period	$	(13,154)
2025	Linking Period	$	(6,709)
2026	Unadjusted Test Year	$	(15,111)
2026	Adjusted Test Year	$	6,061

Q28. Please discuss the differences in net capacity revenue from the Historical Base Period through the Adjusted Test Year.

A28. Two events are driving the changes in the net capacity revenue between the periods on Figure CS-2. Capacity credits from new joint venture generation projects are increasing the amount of capacity in the Company's portfolio. The Hardy Hills solar project added up to 90 MWs of additional capacity, depending on the season, in June 2024. Pike Battery Energy Storage will add 190 MW beginning in June 2025 and Petersburg Energy Center is projected to add up to another 170 MW, depending on the season, in June 2026. The more significant change from the Unadjusted Test Year to the Adjusted Test Year is the inclusion of a full year of Petersburg Generating Station capacity in the Adjusted Test Year. The Unadjusted Test Year does not include Petersburg Unit 3 capacity in the Spring of 2026 and Petersburg Unit 4 capacity in the Summer and Fall of 2026 due to planned outages for the conversion to natural gas.

Q29. What level of capacity cost or credit is AES Indiana proposing for the CAP Adjustment benchmark?

A29. AES Indiana is proposing to embed a $6.1 million credit in the retail revenue requirement reflecting expected net capacity sales, which as stated above, vary by season.[4] The benchmark embedded in the revenue requirement, and the calculation of the value, is shown in AES Indiana Financial Exhibit AESI-OPER, Confidential Schedule REV9-WP4, line 14. This value is total forecasted adjusted test year capacity revenue, AES Indiana Financial Exhibit AESI-OPER, Schedule REV9, line 1, minus total forecasted adjusted test year capacity cost, AES Indiana Financial Exhibit AESI-OPER, Schedule OM3, line 1. AES Indiana witness Aliff discusses AES Indiana's proposal to continue the CAP Rider adjustment mechanism.[5]

Q30. What considerations did the Company give when proposing the benchmark?

A30. As discussed above, the MISO capacity construct and accreditation methodology I discussed above are expected to have a material impact on the Company's capacity position both in the Test Year and going forward. Therefore, the Company reasonably considered the structure of the PRA, the uncertainty around auction clearing prices for each season, and the liquidity of the capacity market in the benchmark proposal.

Q31. Is the Company's proposed benchmark reasonable?

A31. Yes. As with the Company's proposal with OSS Margins, this proposal maintains the benefits of the existing rider structure. Updating the benchmark allows basic rates to be

[4] See AES Indiana Financial Exhibit AESI-OPER, Schedule REV9, line 1 minus AES Indiana Financial Exhibit AESI-OPER, Schedule OM3, line 1.
[5] See also AES Indiana witness Aliff Q/A 41.

representative of revenues and costs the Company expects during the period rates are expected to be in effect. The variability in auction clearing prices, accreditation methodology and planning reserve margins make MISO capacity costs and revenues variable, largely outside AES Indiana’s control, and potentially significant.

5. CONSUMABLES AND EMISSIONS ALLOWANCES EXPENSE

Q32. What consumables are included in the Adjusted Test Year revenue requirement?

A32. Ammonia, coal combustion products, limestone and other chemicals attributed to retail sales are included in the Adjusted Test Year consumables expense. The forecast reflects the conversion of Petersburg from coal to natural gas. Upon conversion, the Company expects lower consumable expenses related to limestone as the flue gas desulfurization system is a post-combustion control for coal-fired generation. In addition, there will be no more production of coal combustion products when coal is no longer the source of fuel. The Company expects continued use of ammonia to run the selective catalytic reduction systems at AES Indiana plants to reduce NOx emissions. Other chemicals include a variety of items used for environmental compliance at the AES Indiana owned plants including the National Pollutant Discharge Elimination System permit compliance.

Q33. Please describe the differences in consumables expense from the Historical Base Period through the Adjusted Test Year.

A33. Table CS-3 shows the Historical Base Period and Linking Period consumables expenses for the Company’s current generation portfolio. The Unadjusted Test Year includes consumable expenses for coal generation for at least one generating unit through June 2026. The Adjusted Test Year forecasts the Company’s annual expected consumables expense assuming Petersburg Units 3 & 4 will operate as converted gas units available for all of 2026, resulting in a lower level of forecasted consumable cost.

Table CS-3: Consumable Cost, 2024-2026

Year	Period		Consumable Cost (000)
2024	Historical Base Period	$	21,887
2025	Linking Period	$	25,908
2026	Unadjusted Test Year	$	9,903
2026	Adjusted Test Year	$	3,956

Q34. What benchmark is the Company proposing for consumables expense and how was the benchmark determined?

A34. The Company is proposing a benchmark for consumables of $4.0 million as shown on <u>AES Indiana Financial Exhibit AESI-OPER, Schedule OM5</u>, line 4. The benchmark was determined by forecasting annual consumable costs for 2026 (assuming Petersburg converted to natural gas for the entire year) and is a decrease of $5.9 million from the Unadjusted Test Year.

Q35. What environmental allowance costs are included in the Adjusted Test Year?

A35. The Company proposes a zero benchmark for environmental allowances, including seasonal NOx, in the Adjusted Test Year, as shown on <u>AES Indiana Financial Exhibit AESI-OPER, Schedule OM8</u>. The removal of coal generation from the Adjusted Test Year significantly reduces the Company's emissions of NOx under existing U.S. Environmental Protection Agency ("EPA") rules. Environmental allowances, including Seasonal NOx, allocated to the Company through various EPA programs are projected to cover emissions in 2026. AES Indiana witness Aliff discusses the continued use of the ECCRA rider to reflect the actual sale or purchase of emission allowances during reconciliation periods.

Q36. Please describe the Company's NOx emission allowances expense from the Historical Base Period through the Adjusted Test Year.

A36. The Company complies through the use of a combination of EPA allocated allowances as well as banked allowances. The lower generation, and by extension emissions, in the Historical Base Period allowed the Company to operate within the bounds of the allocated and banked allowances from the EPA for the NOx season, meaning no additional NOx allowance expenses were incurred.

The challenges to the EPA's Good Neighbor Plan, which govern the Seasonal NOx program, created short-term modifications to the rule in anticipation of a legal outcome on the merits of the case expected in the second quarter of 2025. The modifications removed the short-term expectation that banked allowances would be reduced by a certain percentage, therefore allowing the Company to comply without having to procure additional allowances. The Linking Period forecasts a continuation of allocated allowances covering actual emissions without the need to buy additional allowances under the Good Neighbor Rule as it stands today. That said, the Company's actual experience thus far in 2025 suggests that there may be a need for the Company to acquire or procure additional allowances. The Company continues to monitor the market for NOx transactions through actual bids and offers provided by allowance brokers. The Unadjusted and Adjusted Test Years both have reduced to no coal generation in the seasonal NOx time horizon, May through September 2026, and, therefore, the allocation of allowances from the EPA is currently expected to be sufficient to cover emissions.

Q37. Does the Company propose to continue to track Seasonal NOx allowances?

A37. Yes, the Company proposes to continue to track Seasonal NOx allowances given the potential uncertainty going forward. The EPA's Good Neighbor Plan, which creates the standards for Seasonal NOx, is awaiting a hearing on merits. The outcome of this case and the impact of any successor regulation is unknown. The price of allowances are determined by market supply and demand, therefore, not only are the legal requirements facing the Company are uncertain, the ultimate price of each allowance and total compliance cost are potentially significant and outside of the Company's control. Moreover, continuing to track these expenses allows the Company to recover the cost of procuring additional allowances for compliance while also providing a method to return the proceeds of any future allowance sales to customers as an offset to the cost of service.

6. SUMMARY

Q38. Please summarize your testimony.

A38. My testimony discusses the EnCompass model inputs and outputs and provides background detail and explanation for the forecasted generation cost and quantity estimates. As proposed by the Company, OSS Rider 25 should continue to flow 100% of the Company's OSS margins as a reduction to the cost of service, to the benefit of retail customers. The level of OSS margins embedded in the retail revenue requirement should be decreased from the $28.6 million benchmark in current rates to $24.9 million. Adjusting OSS sales to include a full year of Petersburg availability on gas reasonably normalizes OSS sales for purposes of the benchmark.

Incremental changes in the charges and credits for the net cost and benefit of AES Indiana's participation in MISO's Resource Adequacy Process and the cost and benefit of bilateral capacity transactions should continue to be recognized via the Company's existing CAP

Rider. The retail revenue requirement should include an embedded $6.1 million credit to reflect a net capacity sale varying by season. The structure of the MISO capacity construct and accreditation methodology discussed above are expected to vary annually and impact the Company's capacity position in the Test Year and going forward. That said, the Company's benchmark proposal reasonably considers the structure of the PRA, the uncertainty of auction clearing prices for each season, and the liquidity of the capacity market. Updating the benchmark as proposed by AES Indiana allows basic rates to reflect a representative level of revenues and costs the Company expects during the period rates are projected to be in effect.

Consumable costs are variable, largely outside AES Indiana's control, and potentially significant. The level of consumable expense embedded in the retail rate, $4.0 million, reflects the best estimate of costs in the Adjusted Test Year. Tracking these costs through the ECCRA mechanism aligns the Company and the customers' interest as it allows the Company to timely recover increases in volatile and variable consumable costs as well as return the benefit of lower total consumable costs to customers.

Seasonal NOx allowance costs are also variable, largely outside AES Indiana's control, and potentially significant. NOx emissions, and in conjunction allowance consumption, are a function of generation quantity. The quantity of generation in the Seasonal NOx period is largely driven by weather. Demand for allowances is highly dependent on weather and therefore continues to be variable before and during each NOx season. In addition, the EPA program that establishes NOx emission limits is currently proceeding under a legal challenge with the future of the rule unknown. Because of these conditions, it is difficult to determine a sustainable baseline for purchases or sales. Therefore, the Company's proposal to flow all NOx allowance purchases and sales through the ECR with no benchmark reasonably reflects the actual expense or sales in the ECCRA and aligns the Company's interest with the customer.

Q39. Does this conclude your pre-filed direct testimony?

A39. Yes.

VERIFICATION

I, Caleb Steiner, Director, Regulated Operations and Term Management, US Utilities, affirm under penalties for perjury that the foregoing representations are true to the best of my knowledge, information, and belief.

Caleb Steiner
May 30, 2025