VERIFIED DIRECT TESTIMONY

OF

CALEB STEINER

ON BEHALF OF

INDIANAPOLIS POWER & LIGHT COMPANY

D/B/A AES INDIANA

Cause No. 45911

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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, Commercial Analytics & Strategy, 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, Commercial Analytics & Strategy, US Utilities.

A4. As the Director, Commercial Analytics & Strategy, 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 since 2021. Prior to AES, 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. No.

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 adjustment period generation, generation fuel costs, generation production costs and purchased power costs. My testimony also supports the Company's proposal to maintain the structure of the off-system sales ("OSS") margin adjustment rider No. 25 and the Capacity Adjustment rider No. 24 in their current form with an update to the benchmarks embedded in base rates. I also support the Company's proposal to establish a benchmark in base rates for environmental consumables/commodities and to reconcile the benchmark to actuals in AES Indiana's existing Environmental Compliance Cost Recovery

Adjustment ("ECCRA") Rider No. 20. Finally, my testimony supports the Company's proposal to flow through to rates all NOx emission allowance purchases or sales annually in the ECCRA with no benchmark.

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

A9. Yes. I sponsor or co-sponsor the following financial exhibits or attachments:

- AES Indiana Financial Exhibit AESI-OPER, Schedule-REV6 – Summary of Off-System Sales
- AES Indiana Financial Exhibit AESI-OPER, Schedule-REV9 – Pro Forma Adjustment to Capacity Sales
- AES Indiana Financial Exhibit AESI-OPER, Schedule-OM3 – Pro Forma Adjustment to Capacity Costs
- AES Indiana Financial Exhibit AESI-OPER, Schedule-OM4 – Pro Forma Adjustment to Off-System Sales Power Production Costs
- AES Indiana Financial Exhibit AESI-OPER, Schedule-OM5 – Pro Forma Adjustment to Generation Consumables Variable Expenses
- AES Indiana Financial Exhibit AESI-OPER, Schedule-OM8 – Pro Forma Adjustment to Seasonal NOx Emissions Allowance

Q10. Did you submit any workpapers?

A10. Yes. The calculations shown on the financial exhibits above have been cross-referenced, when appropriate, to the workpapers which provide additional detailed support for these calculations.

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.

2. <u>ENCOMPASS DISPATCH MODEL</u>

Q12. Please provide an overview of the EnCompass dispatch model?

A12. 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 FAC forecasts.

Q13. What are the primary inputs to the EnCompass model and their sources?

A13. The retail load forecast is the weather normalized 2022 test year sales. The generator capacity ratings are consistent with those used for FAC forecasts. The planned outage schedule was used for AES Indiana thermal assets. Actual fuel prices were used if they were under contract for the adjustment period. Forward natural gas prices as of April 26, 2023. The prices for market power are forward prices for MISO Indiana Hub, On-peak and Off-peak as of April 26, 2023.

Q14. What are the primary outputs of the EnCompass model?

A14. 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. The following financial exhibits 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-REV9 – Pro Forma Adjustment to Capacity Sales
- AES Indiana Financial Exhibit AESI-OPER, Schedule-OM2 – Pro Forma Adjustment to Cost of Fuel and Purchased Power (sponsored by witness Dickerson)
- AES Indiana Financial Exhibit AESI-OPER, Schedule-OM3 – Pro Forma Adjustment to Capacity Costs
- AES Indiana Financial Exhibit AESI-OPER, Schedule-OM4 – Pro Forma Adjustment to Off-System Sales Power Production Costs
- AES Indiana Financial Exhibit AESI-OPER, Schedule-OM5 – Pro Forma Adjustment to Generation Consumables Variable Expenses
- AES Indiana Financial Exhibit AESI-OPER, Schedule-OM8 – Pro Forma Adjustment to Seasonal NOx Emissions Allowance

3. OSS MARGINS AND CAPACITY ADJUSTMENT

Off-System Sales ("OSS")

Q15. Please describe an OSS.

A15. 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, the power produced by the Lakefield Wind Project ("LWP"), and the power produced by the Hoosier Wind Project ("HWP").[1] 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).

Q16. What are OSS margins?

A16. 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 incremental generation, until the OSS volumes are satisfied. The Locational Margin Price ("LMP") 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.

Q17. Does the Company intend to continue providing 100% of OSS margin to retail customers?

A17. Yes. The Commission Order approving the settlement agreement in Cause No. 45029 provides that 100% of the Company's OSS margins will be flowed through rates to the benefit of retail customers to allow retail service rates to be reduced by AES Indiana's efforts in the wholesale market. This flow through to customers occurs via Rider 25. As

[1] AES Indiana-owned generation is described by witness Bigalbal on page 4 of his testimony.

stated above, 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 and efforts in the competitive wholesale market to mitigate the overall customer bill.

Q18. Are all OSS margins currently provided to customers through Rider 25??

A18. No. Per the Commission's Order in Cause No. 43740, the OSS margins made possible because of the energy received from LWP are credited to AES Indiana jurisdictional fuel costs through the FAC, which reduces the cost of fuel for retail customers. This credit is referred to as the Lakefield Purchase Power Agreement ("PPA") Adjustment.

Q19. Does the Company propose to continue the practice of crediting LWP to jurisdictional fuel costs through the FAC?

A19. No. The Order in Cause No. 43740 establishing the Lakefield PPA Adjustment occurred before Rider 25 was structured to flow 100% of OSS margins through rates for the benefit of customers. To simplify the OSS and FAC calculations, the Company proposes to include LWP in the OSS margin calculation. This will mean that all OSS margins will be reflected in the Rider 25 filings and removed from the FAC process.

Q20. Does the Company anticipate test year (2022) OSS margins to be representative of margins going forward?

A20. No. The test year OSS margins, before the LWP PPA Adjustment, were $57.8 million and were significantly higher than the 2018-2021 history. The quantity of OSS MWh in the test year was reasonable compared to the 2018-2021 history. However, the $/MWh of margin was five times higher than the average of the previous four years. The MISO Indiana Hub price point is an appropriate proxy for the value of AES Indiana generation on an annual $/MWh basis. Table 1 below shows the differences in annual average Indiana Hub prices from 2018-2022. Higher power prices in 2022 created an opportunity for increased margin from Petersburg units given their relatively fixed priced fuel contracts and from the Eagle Valley combined cycle gas turbine ("EV") due to its low heat rate of 6.7 MMBtu/MWh. The forecast for the adjustment period produced a quantity and margin of OSS greater than the five-year average, 54%, of the forecasted OSS margin comes from just three months of the year. The concentration of forecasted OSS margin in a quarter of the year makes it extremely vulnerable to price and quantity changes in those months.

Table 1: Indiana Hub Prices $/MWh

	Around the Clock (24x7)	Average of on Peak	Average of off Peak
2018	$33.19	$39.00	$28.13
2019	$26.98	$31.21	$23.29
2020	$22.98	$26.70	$19.72
2021	$41.02	$48.45	$34.49
2022	$70.35	$81.76	$60.40

***Information from Morningstar Commodities and Energy Data**

Q21. What is the Company's proposal for treating OSS margins in this case?

A21. AES Indiana proposes to set the benchmark at $28.6 million as shown on AES Indiana Financial Exhibit AESI-OPER, Schedule REV 6 (line 9). As explained by AES Indiana witness Aliff this is an increase of $12.3 million from the $16.3 million benchmark used in

Cause No. 45029.[2] The Company proposes to continue to reconcile actual OSS margins annually in the existing Rider 25. The proposed benchmark is based on the five-year historical average annual MWh attributable to OSS as the sales quantity and a forward looking $/MWh margin to value the OSS MWh. Table 2 shows the last five years of sales through MISO, the 5-year average, and the proposed benchmark. The Company further proposes the pro-forma adjustment of $(76.2) million to AES Indiana Financial Exhibit AESI-OPER, Schedule-OM2 (line 25), sponsored by AES Indiana witness Dickerson, to reclassify off-system sales fuel costs which corresponds to Financial Exhibit AESI-OPER, Schedule REV 6 (line 2 col. 4). In addition the Company proposes a $(14.5) million pro-forma adjustment to off-system sales power production costs as shown in AES Indiana Financial Exhibit AESI-OPER, Schedule-OM4 (line 3). There is a corresponding $(14.5) million adjustment to reclassify OSS fuel against revenue on line 12 of Financial Exhibit AESI-OPER, Schedule REV 6. This follows the OSS margin calculation that subtracts OSS fuel costs and OSS production costs from OSS revenues.

Table 2: Sale Through MISO (in millions)[3]

	MWh Sold	**Fuel Costs**	**Production Costs**	**Total Revenues**	**OSS Margin**
	(1)	(2)	(3)	(4)	(4)-(3)-(2)
2018	1.2	$26.2	$4.2	$38.8	$8.4
2019	2.7	$47.3	$8.3	$68.5	$12.9
2020	2.9	$31.7	$4.8	$46.5	$10.0

[2] See AES Indiana witness Aliff Q/A 21 for discussion of the $12.3 million increase. See Cause No. 45029 Order pp. 15-16 for discussion of the $16.3 million benchmark.
[3] See Workpaper REV6-WP26, for AES Indiana Financial Exhibit AESI-OPER, Schedule-REV6 for proposed OSS Margin.

2021	0.9	$19.6	$2.5	$25.7	$3.7
2022	2.1	$71.4	$14.5	$143.1	$57.1
5-year Average	1.8	$39.2	$6.8	$64.5	$18.4
Proposed Benchmark	1.8	$54.1	$5.7	$88.4	$28.6

Q22. Is the Company's proposal reasonable?

A22. 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. Because OSS margins are volatile, significant, and largely outside AES Indiana's control, embedding a credit in the basic rate revenue requirement that is at the mercy of the wholesale market can unreasonably mask the actual cost of retail service reflected in the basic rate and result in large upward fluctuations in Rider 25. Relying on the five-year average of OSS sales reasonably normalizes OSS sales for purposes of the benchmark using fixed, known, and measurable data. Using the forward looking $/MWh margin value reasonably recognizes that forward power prices are higher than the five-year average at this time and indicate expected $/MWh margins will be higher than the five-year average. This approach to creating the embedded benchmark reasonably reflects current market price conditions while recognizing the uncertainty around OSS.

<u>Capacity Adjustment Rider</u>

Q23. How are charges/credits for capacity generated?

A23. 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 credit for customers via Rider 24.

Q24. Have there been recent changes in the MISO capacity market construct? If so, please explain the changes.

A24. Yes. MISO's 2020 Renewable Integration Impact Assessment ("RIIA") study identified several developing risks to the grid maintaining reliable operation, including the growing penetration of renewables and high-risk hours occurring outside of the typical summer period in their annual capacity construct. In response to these risks, MISO submitted tariff revisions to FERC on November 30, 2021, to establish a seasonal capacity construct. The seasonal resource adequacy construct was approved by FERC on August 31, 2022.[4]

To calculate a utility's capacity requirement for MISO's capacity construct, MISO establishes a PRM based on its Loss of Load Expectation ("LOLE") study. This value is modeled to represent the needed margin above the utility's forecasted peak load for a reliability standard of one day of load loss every ten years. For Planning Year 2022-2023, the Unforced Capacity ("UCAP") PRM was 8.7% as calculated in the LOLE study. This

[4] Dockets Nos. ER22-495-000 & ER22-495-001

means that if all utilities in the MISO footprint carried an average of 8.7% reserves, the expectation would be that every ten years there would be no more than 24 hours of loss of load events within the footprint resulting from peak load exceeding resources available at peak. The PRM is meant to account for forecast error and uncertainty. When the PRM is applied to the forecasted demand at time of MISO peak, the result is the Planning Reserve Margin Requirement ("PRMR").

A comparison of the annual versus seasonal capacity construct is shown in Table 3.

Table 3: Comparison of Annual Versus Seasonal Construct

	Annual Capacity	**Seasonal Capacity Construct**
Resource Adequacy Requirements	MISO performs annual LOLE analysis to determine annual resource adequacy requirements.	MISO calculates 4 distinct sub-annual resource adequacy requirements on a seasonal basis.
Resource Accreditation	MISO accredits conventional resources annually based on a 3-year forced outage rate, excluding planned outage and other exceptions.	MISO accredits by season based on resources availability (SAC) to align resource accreditation with availability in the highest risk periods.
Planning Reserve Auction	MISO conducts annual Planning Resource Auction to meet annual resource adequacy requirements.	MISO conducts independent auctions for all seasons at one time to meet seasonal resource adequacy requirements and will require a Minimum Capacity Obligation (MCI) prior to the auction.

Starting in the 2023-2024 capacity Planning Year, the new seasonal capacity construct was implemented. Under MISO's seasonal resource adequacy construct, summer is defined as June through August, fall is defined as September through November, winter is defined as

December through February, and spring is defined as March through May. This means a different PRM is applied to each season rather than a single number for the entire year. Table 4 displays MISO's estimate of the seasonal PRM values based on MISO's 2022-2023 Planning Year LOLE analysis modeling assumptions. MISO updated these values for the 2023-2024 Planning Year on November 1, 2022.

Table 4: Planning Reserve Margin by Season

Season	PRM (% of Load)
Summer	7.4%
Fall	14.9%
Winter	25.5%
Spring	24.5%

Q25. How has MISO changed the capacity accreditation process for generation resources?

A25. In order to meet the PRMR, resources are assigned UCAP values, which reflect resources' expected availability during peak load. If all resources collectively meet the PRM, the resource adequacy metric is achieved. Alternatively, a short position can be resolved by purchasing capacity in the MISO PRA or through purchases in the bi-lateral market. MISO Seasonal Accredited Capacity ("SAC") gives thermal resources varying UCAP value by four seasons rather than a fixed UCAP value for the entire year. For the SAC, MISO proposes giving resources a capacity credit based on their seasonal availability during all hours – Tier 1 resource adequacy hours and Tier 2 resource adequacy hours. MISO plans to transition this two-tiered weighting in the next three Planning Years as shown in Table 5.

Table 5: MISO Two-Tiered Weighting

	Tier 1	Tier 2
Planning Year 1 (2023-2024)	40%	60%
Planning Year 2 (2024-2025)	30%	70%
Planning Year 3 (2025-2026)	20%	80%

MISO defines resource adequacy hours (Tier 2) as 65 hours in any season during which the capacity is the tightest. Sixty-five is the top 3% of the total hours in any given season (a season is considered 2,190 hours, which is 8,760 divided by 4). Additionally, MISO defines these resource adequacy hours separately for MISO North and South regions because the two regions may not experience coincident hours in which operating conditions are the tightest. Tier 1 hours are all other hours in the corresponding season.

Q26. Do the changes in the MISO capacity construct impact the Company's capacity position?

A26. Yes. The seasonal construct and changes to the accreditation methodology change the capacity position expectations for the Company in the adjustment period. Specifically, MISO now requires the Company to manage four distinct seasons in a year, each with their own PRMR rather than one annual PRMR. At the same time the SAC changed how thermal resources count toward meeting the PRMR in each season. Each of these changes is a significant departure from the prior capacity construct. The fact that they occur simultaneously magnifies their impact on the Company's capacity position.

Q27. How does the Company propose to recover charges/credits for capacity?

A27. 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, as discussed by AES witness Aliff.[5]

Q28. What was the test year level of capacity costs?

A28. The level of capacity costs in the test year was $1.8 million and is shown on line 2 of AES Indiana Financial Exhibit AESI-OPER, Schedule OM3.

Q29. What level of Capacity Cost or Credit is AES Indiana proposing for the CAP Adjustment benchmark?

A29. AES Indiana is proposing to embed $19.0 million in the retail revenue requirement reflecting a net capacity purchase varying by season. The Company has the 2023-2024 PRMR for each season as well as the SAC accreditation for thermal resources and capacity values for non-thermal resources. Moreover, the total quantity and cost or revenue from bilateral transactions is also known at this time. This information combined provides a known capacity position in terms of MWs for 2023-2024 as well as the cost and revenue information outside of the PRA. The Company then used the 2022-2023 PRA clearing price to create a reasonable estimate of the 2023-2024 PRA clearing price in each season to create the benchmark. These calculations are shown in confidential Workpaper OM3-WP2, for AES Indiana Financial Exhibit AESI-OPER, Schedule OM3. The benchmark embedded in the revenue requirement is shown on line 1 of AES Indiana Financial Exhibit AESI-OPER, Schedule OM3. AES witness Aliff discusses AES Indiana's proposal to continue the CAP Rider adjustment mechanism.[6]

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[5] See AES Indiana witness Aliff Q/A 37
[6] *Id*.

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

A30. The significant changes in the MISO capacity construct and accreditation methodology I discussed above are expected to have a material impact on the Company's capacity position in the adjustment period and going forward. Therefore, the Company reasonably considered the new structure of the PRA, the uncertainty around auction clearing prices for each season and the liquidity of the new 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 existing benefits of the Rider structure. Updating the benchmark allows basic rates to be representative and sustainable 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.

4. CONSUMABLES AND EMISSIONS ALLOWANCES EXPENSE

Q32. What consumables are included in test year expense?

A32. Ammonia, coal combustion products, limestone and other chemicals attributed to retail sales are the consumables included in the test year expense. Ammonia is used to run the selective catalytic reduction systems at AES Indiana plants to reduce NO_x emissions. Coal combustion products are different types of coal ash from the combustion process as well as flue gas desulfurization material leftover from the process of removing sulfur dioxide emissions from a coal fired boiler. Limestone is used in the flue gas desulfurization process to remove SO_2 from coal plant emissions. Other chemicals include a variety of items used for environmental compliance at the AES Indiana owned plants including the Mercury Air

Toxics Standards for Power Plants and the National Pollutant Discharge Elimination System permit compliance.

Q33. What is the Company's proposal regarding consumable expenses?

A33. The Company proposes to establish a benchmark and as explained by AES Indiana witness Aliff will annually reconcile the actual expenses in the ECCRA, similar to the processes described above for the OSS and CAP.[7]

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

A34. The Company is proposing a benchmark for consumables of $18.4 million as can be seen on AES Indiana Financial Exhibit AESI-OPER, Schedule OM5. The benchmark was determined by averaging the annual forecasted consumable cost for 2023 and 2024. The two-year average smooths out the impact of planned outages in each year, presenting a representative value. The consumption of Petersburg Unit 2 is also removed to account for its retirement in May 2023.

Q35. Are consumable costs variable, largely outside AES Indiana's control, and potentially significant?

A35. Yes. Consumable quantities vary directly with fuel use of the units. For instance, increasing coal consumption, increases limestone consumption to remove SO2 and ammonia to remove NO_x as well as increases the quantity of coal ash for disposal. The prices for the commodities also vary. For example, the main feedstock for ammonia production in the United States is natural gas and the price of ammonia closely follows natural gas prices

[7] See AES Indiana witness Aliff Q/A 36.

which are extremely variable over time and out of the Company's control. Ammonia costs for retail sales increased from $0.4 million in 2020 to $2.5 million in 2022. Limestone, which is influenced by fuel oil costs for production and transportation, increased from $2.4 million in 2020 to $6.8 million in 2022. Chemicals also increased during this time from $4.8 million in 2020 to $7.6 million in 2022. Table 6 shows total retail consumable costs from 2020-2022.

The EPA regulates the disposal of coal combustion products ("CCP") under the Resource Recovery and Conservation Act. The Company uses specialty contractors to dispose of coal ash and negotiates contract pricing for the disposal. The costs for this disposal increased from $1.1 million in 2020 to $9.3 million in 2022 illustrated in Table 6

Table 6: Retail Consumable Costs 2020-2022 (in millions)

	Ammonia Cost	**CCP Cost**	**Limestone Cost**	**Chemical Cost**
2020	$0.4	$1.1	$2.4	$4.8
2021	$0.9	$2.1	$4.5	$6.6
2022	$2.5	$9.3	$6.8	$7.6

Q36. Why is this proposed ratemaking reasonable?

A36. The proposal is reasonable because it provides a mechanism to align the Company's costs with the customer rates for a variable and potentially significant cost that is outside of the Company's control. The Company proposes to embed in the base rate revenue requirement the cost of consumables based on a two-year forecasted average from 2023 and 2024. This embedded amount will serve as the benchmark in the ECCRA filings that will recognize increases or decreases in these costs. The proposal 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.

Q37. What allowance costs are included in the test year?

A37. The test year Seasonal NO_x allowance costs of $0.9 million have been adjusted to zero as shown on AES Indiana Financial Exhibit AESI-OPER, Schedule OM8.

Q38. What is the Company's proposal regarding allowance expenses?

A38. The Company proposes to flow all NO_x allowance purchases and sales through the ECCRA with no benchmark and as explained by AES Indiana witness Aliff will annually reflect the actual expense or sales in the ECCRA.

Q39. Are Seasonal NO_x allowance costs variable, largely outside AES Indiana's control, and potentially significant?

A39. Yes. In March 2023, the EPA published the final rule updating the seasonal NO_x program. The program, which applies to the months of May through September, added nine states to Indiana's compliance group, Group 3, for a total of 22 states. The rule contains a mechanism to prevent growth in the allowance bank year over year. The allowance bank is a structure that permits an allowance holder to carry over unused allowances from one compliance season to the next. Limits to this bank create uncertainty regarding the overall NO_x allowances available in the market year over year. In addition, Indiana's allocation of allowances was reduced by 11% in 2023. The reduction of overall allowances and the limit on the allowance bank is outside of the Company's control.

Additionally, NO_x emissions, and in conjunction allowance consumption, are a function of generation quantity. The quantity of generation in the seasonal NO_x period is largely driven by weather. Even before the final rule, anticipation of program changes created large swings in the costs of NO_x allowances. In the summer of 2022 market prices for a NO_x allowance reached as high as $47,000 according to broker quotes. Broker quotes for NO_x allowances in the adjustment period are $9,500. Demand for allowances is highly dependent on weather and therefore continues to be variable before and during each NO_x season. Because of these conditions, it is difficult to determine a sustainable baseline for purchases or sales.

Q40. Why is the Company's proposed ratemaking reasonable?

A40. The proposal aligns the Company's interest with the customer. If it is economically beneficial to buy additional allowances beyond the state allocation in order to generate power for the customer, then the Company has the opportunity to recover those allowance costs. If the customer benefits from selling allowances rather than consuming them, this proposal creates a mechanism to return the proceeds to customers.

5. SUMMARY AND RECOMMENDATIONS

Q41. Please summarize your testimony and recommendations.

A41. The overview of the EnCompass model inputs and outputs provided background detail and explanation for the adjustment period generation cost and quantity estimates. As proposed by the Company, OSS Rider 25 should continue to flow 100% of the Company's OSS margins through rates to the benefit of retail customers to allow retail service rates to be reduced by AES Indiana's efforts in the wholesale market. The level of OSS margins embedded in the retail revenue requirement should be increased from $12.3 million benchmark in current rates to $28.6 million. The updated benchmark is based on the five-year historical average annual MWh attributable to OSS as the sales quantity and a forward looking $/MWh margin to value the OSS MWh. Relying on the five-year average of OSS sales reasonably normalizes OSS sales for purposes of the benchmark using fixed, known, and measurable data. Using the forward looking $/MWh margin value reasonably recognizes that forward power prices are higher than the five-year average at this time and indicate expected $/MWh margins will be higher than the five-year average. This approach to creating the embedded benchmark reasonably reflects current market price conditions while recognizing the uncertainty around OSS. This proposal also reasonably allows the Company's basic rates to reflect the cost of providing retail service and efforts in the competitive wholesale market to mitigate the overall customer bill.

The OSS margins made possible because of the energy received from the Lakefield Wind PPA should be moved from the FAC to OSS Rider 25 to simplify the OSS and FAC calculations and allow all OSS margins to be addressed in one proceeding.

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 embed $19.0 million to reflect a net capacity purchase varying by season. The significant changes in the MISO capacity construct and accreditation methodology discussed above are expected to have a material impact on the Company's capacity position in the adjustment period and going forward. The Company's benchmark proposal reasonably considers the new structure of the PRA, the uncertainty around auction clearing prices for each season and the liquidity of the new capacity market. Updating the benchmark as proposed by AES Indiana allows basic rates to reflect a representative and sustainable level of revenues and costs the Company expects during the period rates are expected to be in effect.

The Company's proposed benchmark for consumables expense was reasonably determined by averaging the annual forecasted consumable cost for 2023 and 2024. The two-year average smooths out the impact of planned outages in each year, presenting a representative value. The consumption of Petersburg Unit 2 is also removed to account for its retirement in May 2023. Consumable costs are variable, largely outside AES Indiana's control, and potentially significant. 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 NO_x allowance costs are also variable, largely outside AES Indiana's control, and potentially significant. NO_x emissions, and in conjunction allowance consumption, are a function of generation quantity. The quantity of generation in the seasonal NO_x period is largely driven by weather. Demand for allowances is highly dependent on weather and therefore continues to be variable before and during each NO_x season. Because of these conditions, it is difficult to determine a sustainable baseline for purchases or sales. Therefore, the Company's proposal to flow all NO_x 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.

Q42. Does this conclude your pre-filed direct testimony?

A42. Yes.

VERIFICATION

I, Caleb Steiner, Director, Commercial Analytics & Strategy, US Utilities, affirm under penalties for perjury that the foregoing representations are true to the best of my knowledge, information, and belief.

Caleb Steiner
June 28, 2023