VERIFIED REBUTTAL TESTIMONY

OF

ERIK MILLER

ON BEHALF OF AES INDIANA

CAUSE NO. 46022

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1. INTRODUCTION

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

A1. My name is Erik Miller. I am employed by Indianapolis Power & Light Company d/b/a AES Indiana ("Petitioner," "AES Indiana," or the "Company"), One Monument Circle, Indianapolis, Indiana, 46204.

Q2. What is your position with AES Indiana?

A2. I am Director, Resource Planning.

Q3. Are you the same Erik Miller who previously submitted direct testimony in this Cause?

A3. Yes.

Q4. Please summarize your overall responsibilities as Director, Resource Planning, AES US Utilities.

A4. As further described in my Direct Testimony (Q/A 5), I am responsible for the economics and decision support analysis in the areas of resource planning, environmental planning, and other strategic level analysis. In this role, I am required regularly in the normal course of business to review and interpret regulations and statutes.

Q5. What is the purpose of your rebuttal testimony in this proceeding?

A5. My rebuttal testimony responds to the testimony and recommendations offered by Office of Utility Consumer Counselor ("OUCC") witnesses Brian R. Latham and Roopali

Sanka. I also respond to certain matters raised in the testimony of Intervenor Reliable Energy, Inc. ("REI") witnesses Michael J. Nasi and Emily S. Medine.

Q6. Are you sponsoring any attachments?

A6. Yes. AES Indiana Attachment EKM-1R provides AES Indiana's responses to REI DR 2-1 through 2-9, 2-11, and 2-24 through 2-27 and OUCC DR 3-1.

Q7. Did you submit any workpapers?

A7. No.

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

A8. Yes.

Q9. Does the fact that you do not address every point raised in the OUCC and REI witness testimony mean that you agree with the other party's testimony on those issues?

A9. No. The absence of a specific discussion of every point asserted by the OUCC or Intervenor witnesses should not be viewed as an agreement with such issues.

2. REPLY TO OUCC

Q10. Please summarize the testimony and recommendations of the OUCC witnesses Latham and Sanka.

A10. Below is a summary of the items in Mr. Latham's and Ms. Sanka's testimonies that pertain to the IRP development and analysis that my group performed.

1. OUCC witness Latham performed a simple revenue requirement on the Petersburg Repowering (Project) assuming a rate case in the third year of the Project's operation. OUCC witness Latham compared his calculated benefit to the estimated savings associated with the Project of $437 million as demonstrated in AES Indiana's 2024 IRP Update with Environmental Protection Agency's ("EPA") Greenhouse Gas ("GHG") New Source Performance Standards ("NSPS") (published in the Federal Register on May 9, 2024) (hereafter referred to as "GHG NSPS") compliance included. After making this comparison, he concluded that the OUCC does not have concerns about affordability of the Project at this time. [1]

2. OUCC witness Latham notes that the conversion of Units 3 and 4 will result in significant reductions in most criteria air pollutants, mercury, CO2 emissions and coal combustion residuals. And that these reductions will result in reduced environmental costs.[2]

3. OUCC witness Latham indicates that the Project fits into AES Indiana's goal of no longer relying on coal generation for its energy and capacity needs. He adds that the Company included plans to convert the units to natural gas in its IRP to meet this goal.[3]

4. OUCC witness Sanka reviewed the reliability, stability and resiliency, of the Project and notes that 1) by using existing Petersburg infrastructure and the Midwestern natural gas pipeline, the project avoids $929M (present value) in

[1] Public's Ex. 1 at 5-6.AES Indiana provided the OUCC with the results of the 2024 IRP Update with EPA GHG NSPS Rule compliance included through a virtual meeting conducted on 5/22/2024.
[2] Public's Ex. 1 at 8.
[3] *Id.* at 9.

reliability upgrades over 20 years; 2) the Project reduces risk compared to building a new facility; and 3) the Project will maintain capacity accreditation near or above 90% year-round under MISO's seasonal resource adequacy construct. She concludes that "keeping this substantial, dispatchable generation facility in operation supports reliability, stability and resiliency for AES Indiana and its customers." [4]

5. After noting the updates made to the 2022 IRP as part of the 2024 IRP Update, OUCC witness Latham concludes that the Project is consistent with the 2022 IRP and 2024 IRP Update.[5]

6. In the OUCC recommendations section of his testimony, OUCC witness Latham states that the OUCC does not oppose AES Indiana's proposed Project and Petitioner's related financing plan at the time.[6]

The Company appreciates the OUCC's constructive review of the proposed Project. I provide certain clarifications in my rebuttal below.

Q11. As reflected in the above summary, OUCC witness Latham states that the Project fits into "AES Indiana's goal of no longer relying on coal generation for its energy and capacity needs" and suggests "AES Indiana's 2022 IRP included plans to convert Petersburg to natural gas" to meet this goal.[7] What does OUCC witness Latham base his assertion on?

[4] Public's Ex. 2 at 3-4.
[5] *Id.* at 9-10.
[6] *Id.* at 10. Company witness Rogers further responds to OUCC witness Latham's recommendations.
[7] *Id.* at 9.

A11. Mr. Latham (p. 9, footnote 20) cites page four of the Company's Non-Technical Summary to the IRP, which is IRP Attachment 1-1 and is found in Volume 2 of the IRP.[8] Page 4 of the Non-Technical Summary presents the IRP Preferred Resource Portfolio and Short Term Action Plan, which is the *result* of the IRP process. This reference clarifies:

> Through a transparent planning and stakeholder engagement process that addressed the noted challenges and a comprehensive evaluation of seventeen (17) Scorecard metrics, AES Indiana selected a Preferred Resource Portfolio and Short Term Action Plan that provides affordable, reliable, and sustainable energy for its customers.[9]

Q12. Do you have a further reply to Mr. Latham's assertion?

A12. Yes. I appreciate the OUCC's comments regarding the work performed in the 2022 IRP and the 2024 IRP Update. However, this comment made by OUCC Witness Latham warrants clarification. AES Indiana does not have a goal of no longer relying on coal generation for its capacity and energy needs. The Company's Parent Company, AES, has sustainability targets; however, these targets did not impact AES Indiana's IRP analysis and the Company's decision to repower Petersburg Units 3 and 4 to natural gas. Both the 2022 IRP and the 2024 IRP Update objectively evaluated the strategies for Petersburg across the Five Pillars. The results of the 2022 IRP and 2024 IRP Update identified the Petersburg Repowering as the most affordable, reliable and sustainable options for customers. OUCC witnesses Latham and Sanka provide a nice summary of the IRP analyses and its conclusion in their respective testimony.

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[8] IRP Attachment 1-1 which contains Volume 2 of the 2022 IRP was filed as AES Indiana Attachment EKM-2 with my Direct Testimony in this case.
[9] AES Indiana IRP Non-Technical Summary, p. 4.

3. <u>REPLY TO INTERVENOR REI</u>

Q13. Please summarize the testimony and recommendations of REI Intervenor witnesses Nasi and Medine addressed in your rebuttal.

A13. I address the following REI recommendations:

1. Intervenor witness Nasi asserts (p. 22) that the GHG NSPS significantly impact AES Indiana's proposal to repower Peterburg to natural gas and that in light of these rules the Commission should deny the Company's CPCN for the Petersburg Repowering or, at a minimum abate the proceeding until AES aligns its proposal with the final GHG NSPS. In his testimony, Mr. Nasi presents several reasons for making this recommendation. I will specifically address the following of his assertions in my rebuttal:

   a. Mr. Nasi's assertion (p. 4) that the final GHG NSPS significantly impact the Company's proposal, and therefore, AES Indiana should supplement its case-in-chief to demonstrate whether the Petersburg Repowering is consistent with the GHG NSPS;

   b. Mr. Nasi's (p. 9) contention that because AES Indiana has not updated its case-in-chief, the parties in this case have not had a chance to review and comment on an updated analysis;

   c. Mr. Nasi's claim that AES Indiana decided to repower the units in order to comply with the GHG NSPS (pp. 6, 7) (which is not correct as discussed below);

d. Mr. Nasi's contention that the expense of coal operation versus the operation of repowering the units will remain unknown until we have more certainty regarding the GHG NSPS (p. 12); and

e. Mr. Nasi's claims that AES Indiana's decision to repower the Petersburg units reflects a singular view of energy needs and ignores the comprehensive needs of Indiana (pp. 21-22).

2. REI witness Medine (pp. 5-7) recommends that given the regulatory uncertainty with challenges to the EPA GHG NSPS and Good Neighbor Rules, AES Indiana should not repower the Petersburg Units until the regulations are final and unappealable. In my Rebuttal Testimony, I will review how AES Indiana has already reasonably accounted for regulatory uncertainty in its 2022 IRP and 2024 IRP Update.

3. REI witness Medine (p. 8) asserts that AES Indiana's "IRP is flawed and should not form the basis of the CPCN approval." She identifies (pp. 8- 9) seven primary concerns which I address below. The concerns not addressed by me are addressed by other AES Indiana witnesses in this proceeding.

4. REI witness Medine (p. 4) claims that AES Indiana "failed to adequately demonstrate that its proposal aligns with the Five Pillars." She contends AES Indiana "fail[ed] to consider affordability analysis" (p. 14), also pp 16-19 and contends (p. 19) the proposed repowering does not comply with the affordability metric. Ms. Medine also asserts (pp. 22-32) that the Petersburg repowering has reliability challenges that were not captured in the modeling; that load growth was understated in the Company's 2022 IRP; that AES Indiana did not put an

appropriate effort into modeling gas prices in its IRP; that the Petersburg Repowering is not consistent with the Sustainability pillar because upstream emissions were not modeled; and that continuing to burn coal at Petersburg is more economic than repowering based on the projected capacity factors of each option.

5. REI witness Nasi (pp. 18-19) claims that AES Indiana has failed to meet the requirements of the CPCN statute (Ind. Code ch. 8-1-8.5) because AES Indiana has failed to demonstrate that its proposal is consistent with the Commission's Statewide Energy Plan.

4. REPLY TO REI'S EPA GHG NSPS CONCERNS

Q14. REI witness Nasi (p. 4) asserts that the United States Environmental Protection Agency ("EPA") released final rules on May 9, 2024, that establish carbon dioxide limits for existing coal units, like the Petersburg units at issue, and for existing gas-fired steam generating units such as those that would remain at the site upon the AES fuel switch from coal-to-gas. Are you aware of the EPA Final Rule?

A14. Yes. The EPA Final Rule is titled: "New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units."[10] This Rule is further discussed by Company witness Collier.

[10] The Rule was published by the Environmental Protection Agency ("EPA") on May 9, 2024 at 89 Fed. Reg. 38,798.

Q15. REI witness Nasi (p. 4) states the GHG NSPS "final rules significantly impact AES's proposal in this proceeding". REI witness Medine (p. 6) adds that given the uncertainty associated with the GHG NSPS it "is imprudent for AES to proceeding with its refueling effort at this time." Do you agree?

A15. No. AES reasonably addressed regulatory uncertainty in its 2022 IRP and 2024 IRP Update both of which indicate that the Petersburg Repowering is the most reasonable least cost strategy for customers which performs the best across the Five Pillars.

Q16. Please explain how this regulatory uncertainty is addressed in the 2022 IRP?

A16. In the 2022 IRP, AES Indiana performed a scenario analysis where the Company evaluated the three overarching strategies for the remaining Petersburg Units 3 and 4 (remain on coal, repower to natural gas, and retire and replace the units) under a range of regulatory scenarios. The purpose of the IRP's scenario analysis was to stress test the optimization[11] of the different strategies under a variety of potential regulatory futures or scenarios and evaluate which strategies perform the best across these scenarios given ever present regulatory uncertainty.

As shown in Figure 1 below, the 2022 IRP scenarios included a "No Environmental Action" scenario with no future carbon regulation and repeal of the Inflation Reduction Act ("IRA") renewable resource tax credits, a "Current Trends" scenario with a $6.49/ton carbon price starting in 2028 and IRA tax credits, an "Aggressive Environmental" scenario with a $29/ton carbon tax starting in 2028, and a "Decarbonized Economy"

[11] In the IRP, AES Indiana used the Encompass capacity expansion model to optimize the different portfolios in the scenario analysis. In the optimization, the Encompass model selects the optimal least cost mix of resources to serve customers. This analysis is discussed in my direct testimony on p. 16. The Company used the 20-year PVRR as the affordability metric to evaluate the portfolios in the scenario analysis.

scenario that requires utilities to meet a percentage of their load with clean energy reaching 80% by 2040. Figure 1 demonstrates that the Petersburg Repowering (Conversion) performs better than keeping Petersburg on coal in all potential regulatory futures.[12]

The 2022 IRP Scenario Analysis demonstrates that in the future with no new environmental regulations or IRA tax credits for renewable resources (scenario most beneficial for coal), repowering the units is still more economic for customers than continuing to burn coal due to the lower fixed costs associated with repowering. And, as CO2 regulations become more-and-more stringent across these regulatory futures, coal becomes less-and-less economic indicating that continuing to burn coal is too risky for customers from a regulatory perspective. As Ms. Medine notes herself (p. 6, line 6-7), "as an existing coal-fired plant, Petersburg is already challenged by a host of regulations."

[12] In the 2022 IRP, AES Indiana performed an analysis without a strategy for Petersburg predefined identified in Figure 1 as the "EnCompass Optimization without Predefined Strategy". This analysis was performed as a measure of reasonableness of the other predefined strategies for Petersburg. This analysis resulted in the model picking to repower at least one of the Petersburg units in every scenario.

Figure 1. 2022 IRP Scenario Analysis Results

Candidate Portfolios

	20-Year PVRR	Scenarios: No Environmental Action	Current Trends (Reference Case)	Aggressive Environmental	Decarbonized Economy
Generation Strategies	No Early Retirement	$7,111	$9,572	$11,349	$9,917
	Petersburg Conversion to Natural Gas (est. 2025)	$6,621	$9,330	$11,181	$9,546
	One Petersburg Unit Retires (2026)	$7,462	$9,773	$11,470	$9,955
	Both Petersburg Units Retire (2026 and 2028)	$7,425	$9,618	$11,145	$9,923
	Clean Energy Strategy Both Petersburg Units Retire and Replaced with Wind, Solar, and Storage Resources (2026 and 2028)	$9,211	$9,711	$11,184	$9,690
	EnCompass Optimization without Predefined Strategy	$6,610	$9,262	$10,994*	$9,572
	Encompass Optimization Results by Scenario:	Converts Petersburg Units 3 and 4 in 2025	Converts Petersburg Unit 3 in 2025 and Converts Petersburg Unit 4 in 2027	Converts Petersburg Unit 4 in 2027*	Converts Petersburg Unit 3 in 2025 & Converts Petersburg Unit 4 in 2027

Q17. Please explain further how this regulatory uncertainty was addressed in the 2024 IRP Update that was performed for and discussed in your Direct Testimony in this case.

A17. In preparation for filing this CPCN, AES Indiana updated the 2022 IRP. This analysis was called the 2024 IRP Update. It was reviewed in detail in my Direct Testimony (see pp. 17-37). Upon publication of the GHG NSPS, AES Indiana fine-tuned the regulatory assumptions in the 2024 IRP Update to align specifically with the impacts of the EPA's GHG NSPS. (see analysis details in Q/A 22 below) This analysis demonstrates that the Petersburg Repowering has increased in cost effectiveness (lower present value of revenue requirement of approximately $437 million compared to operating Petersburg as a coal-fired generating plant) for customers under the EPA's GHG NSPS when compared to the 2022 IRP results because the rules contain more aggressive compliance requirements for coal versus gas. This analysis of the EPA GHG NSPS makes it clear that coal faces significant regulatory risk. Whereas natural gas, with approximately half the CO2 emissions per MWh generated compared to coal, is needed to maintain reliability and as a hedge in an environment of regulatory uncertainty.

Q18. REI Witness Nasi (pp. 6-7) states the EPA proposed GHG NSPS "would have essentially required a [coal] unit to convert to natural gas by January 1, 2027", whereas the final GHG NSPS extends that deadline by three years to 2030. He asserts (p. 7) that AES Indiana "appears to be choosing refueling the units as a compliance strategy" to the EPA GHG NSPS. Please respond.

A18. Mr. Nasi contention that the repowering is strategy to comply with the EPA GHG NSPS is not correct. AES Indiana made the decision to repower the Petersburg units to natural gas in 2022 before the GHG NSPS were proposed. This decision was made based on the Petersburg Repowering performing the best across the Five Pillars in the 2022 IRP. The final GHG NSPS does not change this conclusion. To the contrary, the impact of the final GHG NSPS makes Repowering an even better choice.

Q19. REI Witness Nasi (pp. 7, 11) suggests the Company's Repowering Project should be rejected because it is not aligned with the EPA Final GHG NSPS and it is premature to move forward. Please respond.

A19. While the EPA's GHG NSPS differs from the EPA's proposed GHG NSPS in certain respects, these differences do not warrant the rejection of the proposed Repowering. As discussed above, the Company is not pursuing the Repowering to comply with the EPA GHG NSPS. We are pursuing it because this proposal performs best across the Five

Pillars in the 2022 IRP and in the 2024 IRP Update. In the discovery process, the Company demonstrated to the OUCC and REI that the impacts from final GHG NSPS do not change this conclusion. In fact, the EPA GHG NSPS increase the cost to keep Petersburg as a coal-fired resource (see Q/A 22). This is because, under the GHG NSPS, AES Indiana would be required to co-fire the units with natural gas starting 2030 and then either install carbon capture and sequestration on the units by 2032 or retire the units by 2039. REI's witnesses do not mention this analysis that includes the EPA GHG NSPS, but OUCC witness Latham takes this analysis into account in developing the OUCC recommendation.[13]

Q20. Do you agree with REI Witness Nasi that the GHG NSPS injects a "highly complex legal and technical issue" into the analysis of the proposed Repowering?

A20. No. The EPA Final GHG NSPS does not warrant the rejection of the Repowering Project. While not mentioned by the REI witnesses, AES Indiana produced an analysis (described in Q/A 22 below) in response to REI Discovery Request 2-2 that demonstrates the Petersburg Repowering will be largely unaffected by the EPA GHG NSPS. AES Indiana also provided the full summary of the requirements for compliance with the GHG NSPS in its response to REI DR 2. This analysis was provided to both the OUCC and REI. As noted above, to support his conclusion, OUCC witness Lathem included REI DR 2-2, which contains this analysis and its results, as an attachment to his testimony in this proceeding.[14] For ease of reference, I have included the Company's response to REI DR 2-2 with my rebuttal as <u>AES Indiana Attachment EKM-1R</u>.

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[13] Public's Ex. 1 at 6, footnote 12; Attachment BRL-1, AES Indiana's Response to REI DR 2-2.
[14] OUCC witness Latham included Data Request REI DR 2-2 as OUCC Attachment BRL-1 to his testimony.

Q21. Do you agree with REI Witness Nasi's contention (p. 13) that the parties have not had an opportunity to respond to the Company's analysis?

A21. No. As explained above, the Company produced the analysis REI asked for in the discovery process. Mr. Nasi does not mention this, but the OUCC does. The OUCC was able to review and respond to both my Direct Testimony and the updated analysis in their testimony.

In his testimony, OUCC witness Latham identifies the Petersburg Repowering as having a lower Present Value of Revenue Requirements ("PVRR") of approximately $437 million compared to operating Petersburg as a coal-fired generation plant.[15] This is the same PVRR comparison identified in the updated analysis that considers the EPA GHG NSPS which is described in Q/A 22 below. Mr. Latham indicates that he does not have any concerns with the project's affordability based on the costs and benefits of the project and the recovery of the deferred amounts. Additionally, Mr. Latham indicates that the Petersburg Repowering project is consistent with AES Indiana's 2022 IRP and Short Term Action Plan after considering the results of the 2024 IRP Update and the impacts of the GHG NSPS.

Q22. Do you agree with REI that it is necessary to delay this proceeding so that the Company can update its case-in-chief as a result of the final GHG NSPS?

A22. No. I disagree with Mr. Nasi's suggestion that the finalization of the GHG NSPS after the Company pre-filed its Direct Testimony in March somehow warrants a delay of this proceeding. As discussed above, in the 2022 IRP and 2024 IRP Update that were

[15] Public's Ex. 1, pp. 6, 10.

presented as evidence in my pre-filed Direct Testimony, AES Indiana used a carbon price of $6.49/ton starting in 2028 and escalating at around 4% over the planning period as an approximation of carbon regulation like the GHG NSPS. This approach reasonably takes into account the impact of potential GHG regulation.

When REI asked about the impact of the final GHG NSPS in discovery, AES Indiana conducted an analysis for REI and provided it together with responses to additional questions to both OUCC and REI on May 30, 2024. These DR responses are included in my attachment AES Indiana Attachment EKM-1R. This analysis updated the 2024 IRP Update to consider the impact of the rules on the Petersburg strategies. This DR response followed up on an earlier response to an OUCC regarding the impact of the GHG NSPS, which was provided to OUCC and REI on May 3, 2024. Therefore, REI has had the opportunity to both review and respond to AES Indiana's analysis of the EPA GHG NSPS. Notably, this opportunity was sufficient for the OUCC.

Additionally, as AES Indiana witness Bigalbal described in his Direct Testimony (Q/As 52 - 53), a timely Commission decision is necessary to allow AES Indiana to proceed with its construction timeline and allow the resource to receive MISO accreditation as a capacity resource for the Winter 2026-2027 MISO Planning Season for the benefit of customers.

Q23. As you just mentioned, OUCC witness Latham (p. 6) states that the Company estimates that the Preferred Resource Portfolio, which includes the Petersburg Project, has a lower present value revenue requirement of approximately $437 million compared to operating Petersburg as a coal-fired generating plant. Please clarify the methodology used for this analysis.

A23. AES Indiana updated the strategies in 2024 IRP Update for the EPA GHG NSPS compliance requirements. The following paragraphs summarize the assumption updates made to capture compliance with these rules in the 2024 IRP Update and concludes with the results from the analysis.

Across all strategies in the 2024 IRP Update, the Company updated two core modeling assumptions. 1) To avoid double counting the impact of carbon regulation, AES Indiana removed the carbon price of $6.49/ton starting in 2028. As explained above, in the 2022 IRP and the original 2024 IRP Update, this carbon price served as a reasonable proxy for regulation of carbon like the finalized GHG NSPS. 2) The Company updated the commodities to better align with a future that includes the finalized EPA GHG NSPS. AES Indiana used Horizons Fall 2023 Zero Carbon Additions commodities. This set of commodities reasonably represents power, gas, and coal prices in the future with the finalized GHG NSPS.

In the strategy that keeps Petersburg Units 3 and 4 on coal for the planning period, the Company assumed these units would be required to convert to co-fire with 40% natural gas by Jan. 1, 2030, to comply with the GHG NSPS. The co-firing conversion cost was estimated to be about 65% of the cost to convert to 100% natural gas based on Babcock & Wilcox's experience. Adding co-firing would require Petersburg to maintain all existing material handling equipment and a portion of the coal feed and burners. Therefore, there would be little fixed O&M cost benefit. The analysis was also updated to account for the appropriate mix of fuel and variable O&M which assumes co-firing the units with 40% natural gas. The co-fired units were assumed to remain operational through the planning period or through 2042. However, per the EPA GHG NSPS, these units would be required to either retire by 2039 or install CCS by 2032. Either of these options would make continuing to operate Petersburg as a partly coal-fired asset less cost effective by adding cost for CCS or the cost for replacement resources upon retirement.

In contrast, operating Petersburg Units 3 and 4 as repowered natural gas-fired resources starting in 2026 (the request being made in this filing) will largely be unaffected operationally by the EPA GHG NSPS because the repowered units are expected to achieve the presumptively approvable emissions limitations for existing natural gas-fired steam generating electric generating units, which are based on routine methods of operation and maintenance. As such, in the strategy that converts Petersburg Units 3 and 4 to operate on natural gas, the units were assumed to operate consistent with the operational parameters of the 2024 IRP Update included in my Direct Testimony. Lastly, the strategies that retire and replace Petersburg Units 3 and 4 with other resources were unaffected by compliance with the GHG NSPS because both strategies replace the units with wind, solar and storage resources.

Q24. Was the basis for this analysis explained to REI in the discovery process?

A24. Yes. See AES Indiana's response in AES Indiana Attachment EKM-1R.

Q25. Is OUCC witness Latham's statement (p. 6) correct, that the Company's Preferred Resource Portfolio, which includes the Petersburg Project, has a lower present value revenue requirement of approximately $437 million compared to operating Petersburg as a coal-fired generating plant?

A25. Yes. This statement accurately reflects the Company's analysis including the impact of the EPA GHG NSPS but clarification is warranted to avoid confusion.

Figure 2 below provides the results of this analysis. The Petersburg Repowering is now $437 million lower in terms of PVRR over the planning period than keeping Petersburg as a coal and gas co-fired resource. Also, note that the "No Early Retirement" strategy assumes Petersburg Units 3 and 4 operate as a co-fired resource to comply with the GHG NSPS through the planning period which runs to 2042. However, per the GHG NSPS, either CCS would need to be installed on these units in 2032 or they would need to be retired by 2039. Neither of these requirements were considered in the analysis. Compliance with either of these options would make the units more costly and comparatively less cost effective from a PVRR perspective in the analysis.

Figure 2. 2024 IRP Update with Cost of EPA GHG NSPS Compliance ($M)

	2022 IRP 20-yr PVRR ($M)	2024 IRP Update ($M)	2024 IRP Update w/ EPA Rule Compliance ($M)	Reliability Costs ($M)	2024 IRP Update with Reliability Cost ($M)	2024 IRP Update w/ EPA Rule Compliance and Reliability Cost ($M)
No Early Retirement (Units Co-fired with 40% NG by 2030 through analysis period)*	$ 9,572	$ 9,449	$ 9,192	$ 126	$ 9,575	$ 9,318
Petersburg Conversion to Natural Gas (est. 2026)	$ 9,330	$ 9,168	$ 8,745	$ 136	$ 9,304	$ 8,881
Both Petersburg Units Retire (2027 and 2029)	$ 9,618	$ 9,596	$ 9,343	$ 929	$ 10,525	$ 10,272
Clean Energy Strategy - Both Petersburg Units Retire and Replaced with Wind, Solar and Storage (2027 and 2029)	$ 9,711	$ 9,604	$ 9,352	$ 929	$ 10,533	$ 10,281

Q26. Was this explained to REI through the discovery process?

A26. Yes. See AES Indiana's response to REI DR 2-2 in AES Indiana Attachment EKM-1R.

Q27. REI witness Nasi (pp. 7-11) claims that, until the State of Indiana develops a plan for establishment and enforcement of CO2-specific standards in response to the EPA GHG NSPS, all of the AES assumptions about the relative expense of continued operation of the coal units compared to the expense of Petersburg Repowering are premature. Do you agree?

A27. No. There is a definite decrease in fixed O&M from converting the units from coal to natural gas that will occur regardless of the State's enforcement of the GHG NSPS. This decrease comes from the removal of the cost to operate coal handling and coal emissions equipment and is the primary driver behind the cost effectiveness of repowering the units compared to keeping them on coal. As demonstrated in the 2022 IRP Scenario analysis, regardless of the future regulations analyzed, AES Indiana and its customers will receive these fixed O&M cost reductions.

Q28. REI witness Nasi (pp. 21-22) asserts that AES's IRP and its decision to repower Petersburg Units 3 and 4 "reflects AES's singular view of energy needs of only the AES system and ignores the comprehensive needs of Indiana, which the Commission's Statewide Analysis is meant to provide." Please respond.

A28. The Petersburg Repowering Project offers one-for-one replacement natural gas capacity for Units 3 & 4. These units will maintain dispatchability, thereby preserving reliability for AES Indiana customers and more broadly the State of Indiana and MISO.

5. <u>REPLY TO REI'S ISSUES WITH THE 2022 IRP</u>

Q29. Please summarize REI witness Medine's contention that AES Indiana's IRP is flawed and should not be the basis of the CPCN for approval.

A29. Ms. Medine provided seven primary concerns regarding AES Indiana's IRP. As presented in her testimony (pp. 8-9), Ms. Medine's concerns are:

1) AES Indiana's IRP was designed and hard coded to favor the Petersburg refueling option in support of corporate goals;

2) AES Indiana improperly used a single, inflated, artificial coal price input instead of a range of accurate, market;

3) the IRP resulted in an over-reliance on renewables;

4) AES Indiana used flawed depreciation assumptions for new fossil investments;

5) AES Indiana failed to consider the uncertainty of the Good Neighbor Rule;

6) AES failed to properly consider the Affordability Pillar consistent with state requirements; and

7) AES Indiana did not consider the option to sell Petersburg to a third party as mandated by the state statute.

I address REI and Ms. Medine's concerns below. Many of the aforementioned concerns are also addressed by other Company witnesses in their rebuttal testimony.

Q30. REI witness Medine asserts (p. 8) that "AES Indiana's (2022) IRP was designed and hard coded to favor the Petersburg refueling option in support of corporate goals." How do you respond to this assertion?

A30. This contention is not accurate. Throughout the 2022 IRP planning process, AES Indiana made it clear to stakeholders that the AES Parent Company's sustainability initiatives and target to exit coal had no bearing on the 2022 IRP analysis or decision-making process.[16] Additionally, the Parent Company recognizes that, as a regulated vertically integrated utility operating in the State of Indiana, AES Indiana must perform and demonstrate an unbiased and robust IRP analysis to support its resource decisions – like repowering the Petersburg Units.[17] The 2022 IRP was conducted as an unbiased analysis using reasonable and defensible assumptions that were stress tested using various scenario, stochastic, and sensitivity analyses. These assumptions were updated in the 2024 IRP Update to account for changing market conditions and environmental regulations. The decision to repower Petersburg Units 3 and 4 consistently provides customers cost savings across the sensitivities and scenarios analyzed. Additionally, in the face of regulatory uncertainty, repowering the units provides a rational hedge against imminent regulation of CO2. REI witness Medine's claim (p. 8) that "AES Indiana's IRP was designed and hard coded to favor the Petersburg refueling option in support of corporate goals" is also addressed by AES Indiana witnesses Bigalbal (Section 2) and Cooper (p. 5) in their Rebuttal Testimony.

Q31. Turning now to REI witness Medine's concerns with the coal pricing inputs used in the 2022 IRP. Ms. Medine asserts that AES Indiana did not account for coal price variability in its 2022 IRP stating (p. 11) that "the same coal price forecast was used for the different scenarios." Is this correct?

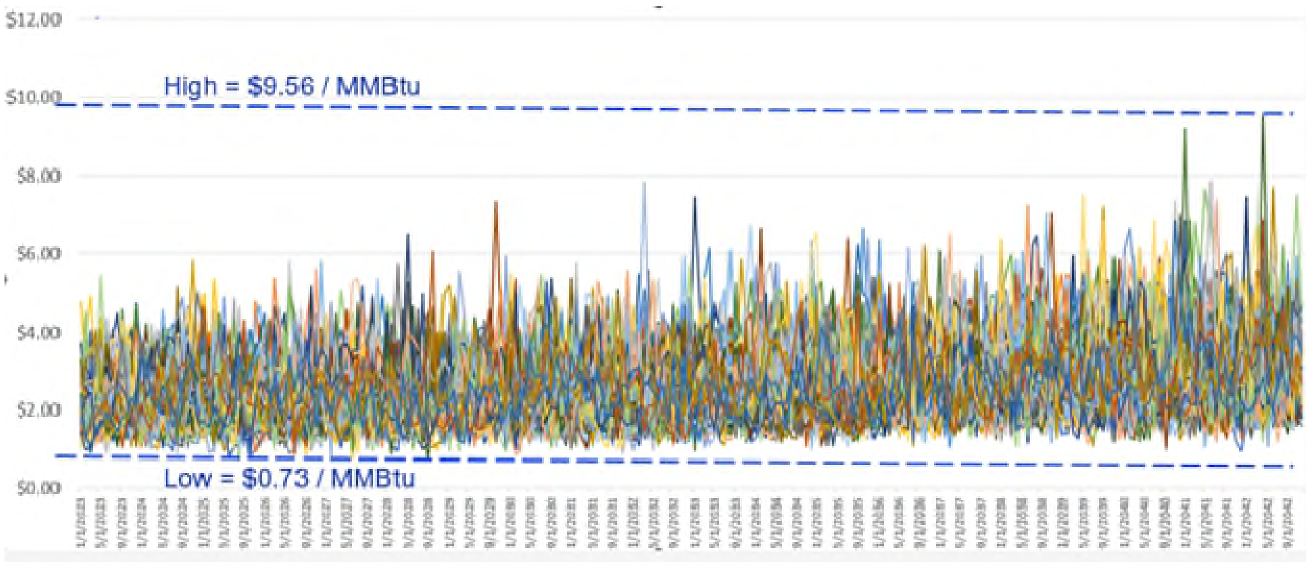
A31. No. The 2022 IRP Scenario Analysis was a deterministic analysis that included a single base case set of coal prices. AES Indiana accounted for the variability of coal prices in

[16] See also Rebuttal Testimony of AES Indiana witness Bigalbal, Section 2.
[17] See AES Indiana witness Bigalbal's Rebuttal Testimony, Section 2.

the Stochastic Analysis that was performed as part of the 2022 IRP to assess potential risks and opportunities to PVRR associated with the variability in commodity prices, load and renewable energy generation of the different Petersburg strategies. In the stochastic analysis, the Company varied not only coal prices, but power prices, gas prices, load and renewable energy generation in 100 unique iterations or outcomes for each of the different Petersburg strategies. The analysis measured the resulting P5 (as opportunity) and P95 (as risk) of the PVRR over the 100 iterations for each Petersburg Strategy. The analysis results indicate that the Petersburg Repowering has the lowest P95 risk when compared to the other strategies including keeping Petersburg as a coal resource (see 2022 IRP Volume 1, pp. 245-249).

Figure 3 visually illustrates just how much coal price variability was included in the 2022 IRP Stochastic Analysis. The analysis included coal prices reaching as low as \$0.73/MMBtu and as high as \$9.56/MMBtu. As demonstrated, this approach reasonably captures variability and volatility in coal prices as well as gas prices, power prices, load and renewable energy generation to ensure an unbiased IRP analysis across uncertain futures.

Figure 3. Coal Prices (100 iterations) included in 2022 IRP Stochastic Analysis



Q32. REI witness Medine (p. 11) disagrees with AES Indiana's methodology for forecasting coal prices stating that "this approach is not industry practice". Please clarify how the Company forecast coal prices in the 2022 IRP.

A32. To forecast coal prices, AES Indiana used actual coal offers or contracted coal prices to forecast the initial forecast year and applied the growth rates from Horizon Illinois Basin Fundamental Forecast to forecast how the prices change over the planning horizon. This methodology is completely reasonable and consistent with industry practice because it captures the exact transaction price paid by or offered to AES Indiana as a starting point for the forecast.

Finally, while Ms. Medine has always been quick to criticize AES Indiana's methodology for forecasting coal prices, she has never recommended an alternative methodology or identified what is industry best practice.

Q33. Ms. Medine also expresses concern (pp. 10-11) that the coal prices that were included in the 2022 IRP were too high because coal prices were inflated at the time due in part to the Russian invasion of Ukraine. Did AES Indiana address this concern in the 2022 IRP?

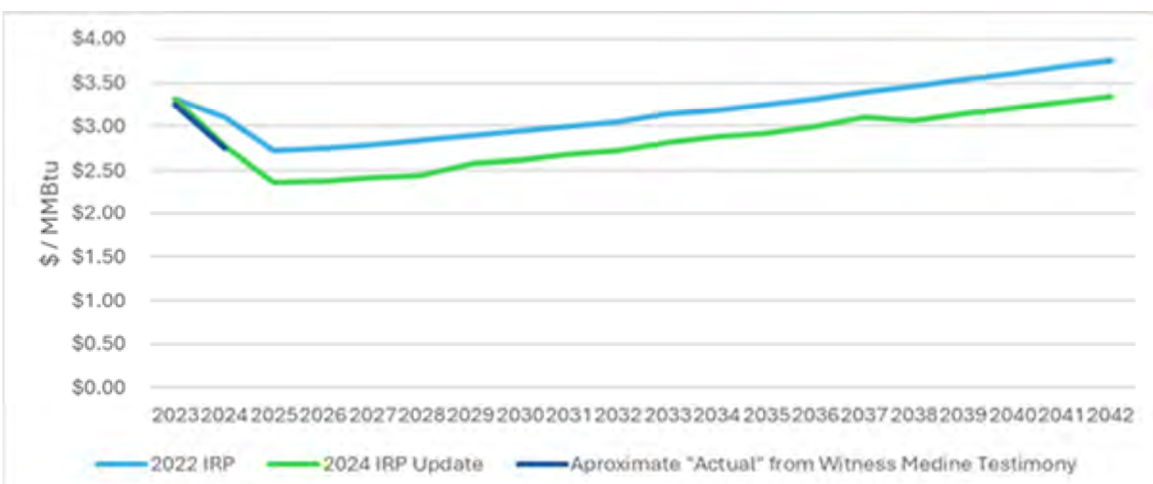
A33. Yes. All commodity prices (power, gas, and coal) – not just coal – at the time of the 2022 IRP experienced inflation largely due to the war in Ukraine and the energy crisis in Europe. Accordingly, in the 2022 IRP, the Stochastic Analysis described in Q/A 31 was performed to understand the sensitivity of the Petersburg Strategies to price variability and volatility. As noted on p. 176 of the Company's 2022 IRP Volume 1 regarding the purpose of the Stochastic Analysis, "The [commodity price] increases were largely driven by an ongoing energy crisis in Europe exacerbated by Russia's invasion of Ukraine, along with other economic factors. These price spikes have raised focus on understanding the sensitivity of the candidate portfolios to the volatility in these commodities." The results of this analysis are also discussed in Q/A 31.

Q34. REI witness Medine (pp. 11-12) asserts that the "actual data for the first three months of 2024 are already demonstrably below the [coal price] forecast [used in the Company's 2022 IRP]". Does this invalidate the Company's analysis or warrant the rejection of the proposed Repowering Project?

A34. No. In the 2024 IRP Update, AES Indiana appropriately updated the base case coal prices (see AES Indiana witness Miller Direct, p. 24). AES Indiana used actual contracted coal prices through 2025 and applied Horizon Spring 2023 Illinois Basin Fundamental Forecast growth rates over the planning horizon to project coal prices. Coal prices decreased by 11.9% in the updated analysis based on updated coal agreement pricing which reflects more stable market conditions compared to 2022.

Figure 3A compares the coal prices used by AES Indiana in its 2022 IRP and 2024 IRP Update to Ms. Medine's representation of the "actual" coal prices (REI witness Medine Direct Testimony, p. 12). This Figure is similar to the chart Ms. Medine included in her testimony (p. 12) but with a more accurate comparison. For whatever reason, Ms. Medine chose to leave out the 2024 IRP Update coal prices in her chart. When the coal prices used in the 2024 IRP Update are included (represented as the green line), AES Indiana has accurately captured the "actual" decreasing coal price trend noted by Ms. Medine. Therefore, this concern does not invalidate the Company's analysis or warrant the rejection of the proposed Repowering Project.

Figure 3A. 2022 IRP, 2024 IRP Update and Medine "Actual" Coal Price Comparisons



Q35. REI witness Medine asserts (p. 13) that the 2022 IRP assumes an over-reliance on renewables because the Company assumes 45% of its generation will come from renewables by 2032. She indicates (p. 13) that this is unrealistic due to the challenges seen across the country to renewable projects. How do you respond?

A35. In the 2022 IRP and 2024 IRP update, AES Indiana accounted for the near-term challenges for renewables by constraining the volume of renewables the model could select at the beginning of the study period. More specifically, given the challenges for citing wind in Indiana, the Company capped the volume of wind available in Northern Indiana for the first five years of the study period and eliminated Northern Indiana wind altogether thereafter.

Additionally, Ms. Medine is focused on the year 2032 which is when Harding Street units 4, 5, and 6 (approximately 600 MW of capacity) are assumed to be retired. The 2022 IRP picked a large volume of renewables to replace these units in the 2030s which largely drives the "45% renewable generation" Ms. Medine references. Ultimately, the 2030 planning period is far beyond the Short Term Action Plan window (2023 – 2027). AES Indiana will conduct another IRP in 2025 that reevaluates strategies for this period. This update will include assumption updates that account for renewable energy availability and accreditation. Most importantly, the Short Term Action Plan period which includes the Petersburg Repowering and the Pike County Battery Energy Storage Project[18] are realistic and deliverable.

[18] Approved by the IURC in Cause No. 45920.

Q36. Ms. Medine also asserts (p. 14) that the IRP contains flawed assumptions for depreciation periods for new fossil fuel investments. She asserts (p. 14) that, because the Company's parent, AES, has announced a net zero by 2040 target, "any new gas investment should be justified based upon firm retirement date of 2040, not the 20 years AES [Indiana] appeared to use in its IRP". How do you respond?

A36. First, as I have already addressed in Q/A 30, AES Indiana's Parent Company targets were not considered in the IRP analysis. This is further addressed in AES Indiana witness Bigalbal's Rebuttal Testimony (Section 2). The 2022 IRP and 2024 IRP Update were conducted using an unbiased approach that used sensitivity and scenario analyses to evaluate the Petersburg strategies across the Five Pillars and make a reasonable least cost decision for customers.

Second, in the 2022 IRP and 2024 IRP Update, Petersburg is assumed to operate through the planning period (2023 – 2042) in both the strategy that continues to operate the units on coal and the strategy that repowers the units to gas. Thus, depreciation and decommissioning were assumed to be the same in both strategies because both strategies assume the same book life. If AES Indiana were to move up the retirement of the Petersburg Repowering, then the Company would have to do the same for the strategy that continues to operate Petersburg on coal thereby affecting the cost of both strategies equally. Consequently, this criticism does not invalidate the Company's analysis or warrant the rejection of the proposed Project.

Q37. REI witness Medine (p. 14) also asserts that the Company failed to consider the uncertainty of the Good Neighbor Rule in the Company's in the IRP. She indicates that the outcome of the Good Neighbor Rule could profoundly affect whether and to what extent the repowered units would be allowed to operate and the amount of power they will be allowed to produce. How do you respond?

A37. I disagree that this was not reasonably taken into account. In the 2022 IRP, AES Indiana assumed NOx prices increased to $14,000/ton in 2027 to account for potential changes in the Good Neighbor Rule. The Petersburg Repowering is still demonstrated to be the most Affordable option for customers with these NOx prices included in the analysis. Company witness Collier discusses the anticipated impacts of the Good Neighbor Rule on the Repowered Petersburg units in her Rebuttal Testimony (Section 2).

Q38. REI witness Medine indicates (p. 16) that the NPV analysis provided in the IRP is insufficient because AES ignores the impact to customers of the undepreciated costs (sunk cost) associated with early retirements of the units. Please respond.

A38. AES Indiana is not retiring Petersburg. The Company is repowering the units to operate on natural gas. The Company will continue to recover the undepreciated costs for Petersburg and any additional capital expenditures for the repowering over the remaining book life of Petersburg which is the same whether the units remain on coal, are retired, or are repowered to natural gas. In conclusion, the NPV analysis provided in the IRP is correct concerning the treatment of undepreciated costs for the Petersburg Repowering.

Q39. REI witness Medine (p. 19) comments on the 10- and 20-year PVRR analysis PVRR analysis provided in the 2024 IRP Update and asserts that "[t]here appears to be no financial benefit given the equivalent NPV for the 10-yr period". Is this a reason to reject the proposed Repowering Project?

A39. No. Ms. Medine ignores risk and the other Pillars in her analysis. First, her claim fails to account for the demonstrated risk that remaining on coal at Petersburg poses to AES Indiana customers. AES Indiana demonstrated in its 2022 IRP that as regulation on CO2 becomes more stringent, the cost to operate Petersburg as a coal resource becomes more expensive and less cost effective compared to operating the units on natural gas. This analysis is discussed in Q/A 30-34. Additionally, after accounting for the EPA GHG NSPS, which pose much tighter regulations on coal resources compared to natural gas, the strategy to remain on coal at Petersburg becomes even less cost effective.

Figure 4 below provides the 10-year PVRR comparison after including compliance with the EPA GHG NSPS in the 2024 IRP Update. The figure demonstrates that repowering the units to natural gas costs nearly $100M less than keeping the units on coal over that 10-year period. This analysis is discussed in more detail in Q/A 17. Ultimately, the Petersburg Repowering provides AES Indiana customers with a reasonable hedge against the cost to comply with pending regulation on CO2.

Figure 4. 2024 IRP Update with EPA GHG NSPS Impact 10-year PVRR

10-yr PVRR	2024 IRP Update ($M)
No Early Retirement	$5,391
Petersburg Conversion to Natural Gas (est. 2026)	$5,298
Both Petersburg Units Retire (2026/2027 and 2028/2029)	$5,519
Clean Energy Strategy - Both Petersburg Units Retire and Replaced with Wind, Solar and Storage (2026/2027 and 2028/2029)	$5,515

Ms. Medine also fails to consider the sustainability benefits of repowering the units to natural gas which will result in half the CO2 per MWh generated, eliminate SO2 and coal combustion waste, and greatly reduce particulate matter (all of which come with associated costs).

Q40. REI witness Medine (p. 24) also asserts that future load growth in combination with coal plant retirements has created reliability risk. She points (p. 25) to examples of announced coal plant retirements being delayed. She states (p. 25) that the "point is any decision to retire an operating coal plant at a specific time must be reconsidered in the context of higher load growth, supply chain delays, and higher cost associated with replacement capacity." How do you respond?

A40. AES Indiana is not retiring Petersburg. The Company is repowering the existing coal plant infrastructure to operate on natural gas. Repowering the plant poses very low execution risk compared to retiring and replacing the units with other resources like wind, solar and storage. The Company has already successfully demonstrated a coal-to-gas conversion with the Company's Harding Street Steam Units 5, 6, and 7 which were converted in 2016. In the examples Ms. Medine references where utilities have delayed retirement of their coal units (Medine p. 25, lines 1-10), this has been because they were replacing the units with renewable resources which face development challenges. For example, the NIPSCO announcement she cites is dated June 1, 2022 and states that the delay is necessary because of the then current federal solar tariff investigation, which involved potential trade violations involving solar panels bought from Asian suppliers.[19] Also of note, the retirement of the Edgewater plant in Wisconsin that Ms. Medine cites (p. 25) as an example was delayed from 2022 to 2025 because of the renewable challenges that I previously noted. Alliant has now determined the best option for this plant will be to convert to natural gas in 2028 like the repowering of Petersburg.[20] Another recent example of coal plant conversions not mentioned by Medine is that of PacifiCorp. The Company's recent 2023 IRP announced the intention to greatly reduce coal-fired generation by 2030. Four of the Company's coal-fired units will convert to natural gas by 2030.[21]

Q41. REI witness Medine asserts (p. 25) that the load growth that was included in the 2022 IRP was understated. How do you respond?

A41. In the 2022 IRP, AES Indiana assessed a range of load sensitivities in the deterministic IRP Scenario Analysis. The load variability in these sensitivities was driven by low, base, and high economic forecasts; low, base, high and very high electric vehicle forecasts; and low, base and high customer solar forecasts.[22] AES Indiana engaged with stakeholders through the stakeholder process to define these load forecasts. The base

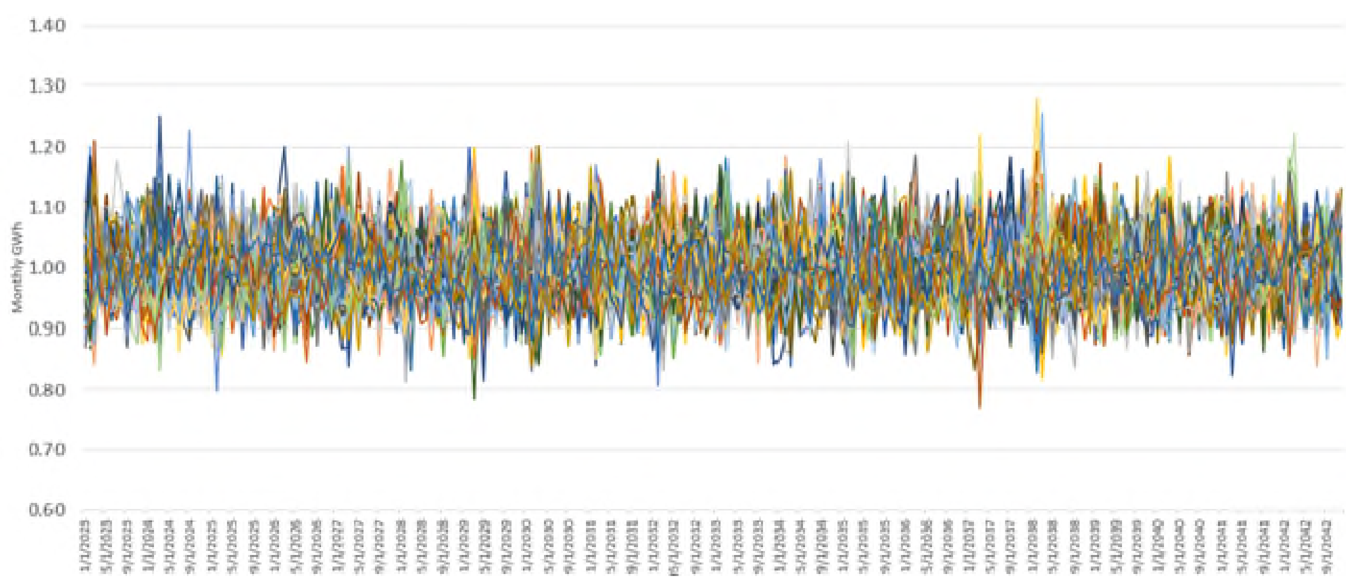
19 https://www.newsbug.info/rensselaer_republican/news/nipsco-need-to-delay-schahfer-closing-until-2025/article_6af9c081-5a1a-5431-84ba-778058fca38a.html
20 https://www.alliantenergy.com/alliantenergynews/newscenter/052324-generationupdate.
21 https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2023-irp/2023_IRP_Volume_I.pdf
22 See 2022 IRP Volume 1, p. 153, 8.4.2 Scenario Framework

load forecast which contained base assumptions for the economic outlook, electric vehicles and customer solar was modeled in the Current Trends/Reference Case scenario to select the Short Term Action Plan and Preferred Resource Portfolio.

Additionally, the Company performed a Stochastic Analysis to further assess risk associated with load variability and volatility. As previously discussed in Q/A 31, this analysis varied not only load, but gas prices, power prices, coal, prices and renewable energy generation over 100 unique iterations.

Figure 5 below illustrates the range of load that AES Indiana modeled in the stochastic analysis. Results from the Stochastic Analysis are also discussed in Q/A 31. Contrary to Ms. Medine's assertion, AES Indiana evaluated the risk to the strategies for Petersburg using a range of load forecasts both much higher and much lower than the base case load forecast. Accordingly, this criticism does not warrant the rejection of the proposed Project.

Figure 5. Load Forecasts (100 iterations) included in 2022 IRP Stochastic



Q42. REI witness Medine (p. 26) claims that you acknowledged the load forecast was understated when you indicated in your Direct Testimony that AES Indiana now needs approximately 200 MW of additional capacity in 2025. Do you agree?

A42. No. The load forecast reflected in the IRP was reasonable at the time the IRP analysis was performed. As discussed in my Direct testimony, the need for additional 200 MW of battery energy storage was primarily driven by MISO updating the winter planning reserve margin from 21.4% during the 2022 IRP to 27.4% during the 2024 IRP Update; not due to an increase in the load forecast as Ms. Medine asserts (p. 26). In my Direct Testimony (Q/A 25), I specifically stated, "after updating to the most recent higher MISO planning reserve margins, AES Indiana now needs approximately 200 MW of additional capacity starting in 2025." Ms. Medine does not point out that the updated forecasted peaks actually went down by approximately 6% on average in the summer and slightly up by 1% in the winter as discussed in Q/A 24 of my Direct Testimony.

Consistent with the Commission's IRP rules, AES Indiana appropriately updated the load forecast assumptions for the 2024 IRP Update included in this CPCN as well as many other assumptions included in this update and discussed in Q/A 24 of my Direct Testimony. In making this update, AES Indiana reasonably captured the most contemporary load forecast for the analysis and was agnostic to whether the forecast was higher or lower than the forecast included in the 2022 IRP.

Q43. Ms. Medine (p. 27) asserts that the proposed Repowering Project "is not an ideal long-term solution because, as Mr. Nasi testified, the units face the strong possibility that they will not be allowed to be used at their anticipated output due to environmental regulations." Do you agree that resource decisions should be based on "possibilities"?

A43. No. The Company's resource planning and decision-making process reasonably relies on a sound factual and analytical foundation and uses numerous sensitivities to gauge performance over various uncertain futures. While other stakeholders may disagree with the Company's views on assumptions and inputs, it is important to realize that the Company's approach does not rest on speculation about what may be possible.

Q44. Please respond further to the above referenced contention made by REI witness Medine.

A44. As previously discussed, the Petersburg Repowering offers a rational hedge against CO_2 and coal-targeted regulations. This has been demonstrated in AES Indiana's 2022 IRP Scenario Analysis, in the 2024 IRP Update, and in the 2024 IRP Update that reflects the GHG NSPS. See Q/A 16. Additionally, the units are expected to achieve the presumptively approvable emissions limitations for existing natural gas-fired steam generating electric generating units, which are based on routine methods of operation and maintenance. The repowered units will maintain reliable, firm capacity at Petersburg, result in lower fixed O&M costs compared to coal and provide more sustainable operation by generating half the CO_2 per MWh compared to coal. In her rebuttal, AES Indiana witness Collier (Section 3) refutes the REI contentions that the GHG NSPS warrant the rejection of the proposed Project.

Q45. Turning now to the gas prices included in the IRP analyses, REI witness Medine (p. 28) points out that AES Indiana reduced the natural gas prices (by 10.6%) in the 2024 IRP Update. She claims (p. 28) that similar to her view on coal, the update "should not have been necessary had appropriate effort been expended in their development" for the 2022 IRP. How do you respond?

A45. The coal and natural gas prices forecasts used in the IRP were reasonable at the time the IRP analysis was conducted. The purpose of the 2024 IRP Update was to update the assumptions that were used in the 2022 IRP to reflect changes in the market and reassess the IRP analysis to see if the Petersburg Repowering is still the best strategy for customers. AES Indiana appropriately updated gas and coal prices along with other key assumptions that reflect market changes since the IRP was conducted in 2022. In making this update, both gas and coal prices dropped by similar amounts due to greater market stability in 2024. The 2024 IRP Update with the updated assumptions demonstrates that the Petersburg Repowering is still the most affordable, reliable and sustainable strategy for AES Indiana Customers.

Additionally, as previously discussed in Q/As 31 and 41, AES Indiana performed a Stochastic Analysis as part of the Company's 2022 IRP. The analysis captured variability in natural gas prices as well as coal, power, load and renewable energy generation over 100 unique stochastic iterations.[23] Ms. Medine's suggestion that the Company did not reasonably address natural gas price uncertainty is without merit. AES Indiana's Stochastic Analysis that was conducted as part of the 2022 IRP captured the volatility in natural gas and coal prices over 100 unique iterations. The analysis found

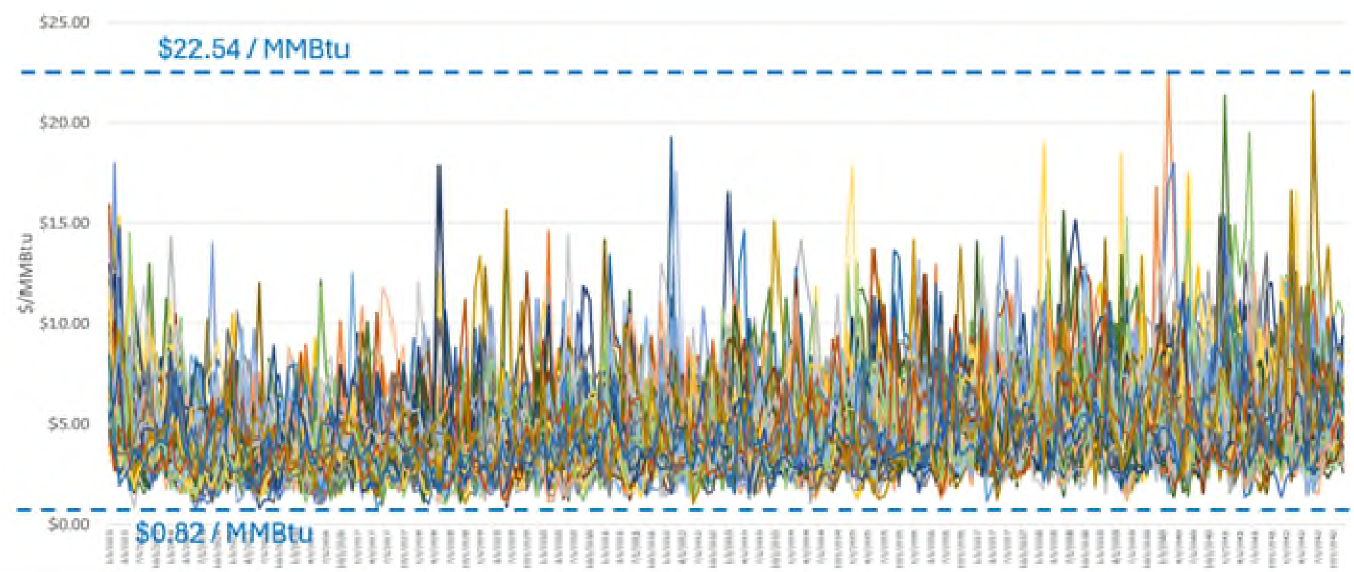
[23] Also see AES Indiana 2022 IRP Volume 1, p. 176 – 178.

that the Petersburg Repowering strategy performed better with lower P95 risk when compared to keeping Petersburg on coal.

Figure 6 below illustrates the natural gas volatility modeled in the 100 forecast iterations included in the 2022 IRP Stochastic Analysis. The analysis included natural gas prices as high as $22.54/MMBtu and as low as $0.78/MMBtu.

Contrary to Ms. Medine's claim, AES Indiana put considerable thought, time, and effort into developing and evaluating the assumptions, including natural gas and coal prices, in its 2022 IRP and 2024 IRP Update.

Figure 6. Natural Gas Prices (100 iterations) included in 2022 IRP Stochastic Analysis



Q46. Please elaborate on your statement in Q/A 41 above that the Company's 2022 IRP and the 2024 IRP Update presented in your Direct Testimony are consistent with the Commission's IRP rules.

A46. AES Indiana followed the IRP Rules contained in 170 IAC 4-7 in conducting its 2022 IRP. This includes appropriately evaluating the Affordability Pillar by using both the 10-year and 20-year PVRR and "the present value of revenue requirement for each candidate portfolio in dollars per kilowatt-hour delivered with interest rate applied." (see AES Indiana 2022 IRP Volume 1, p. 186)

The Company updated the IRP in the 2024 IRP Update (see my Direct Testimony, Section 3) for relevant market and environmental regulation changes to confirm the 2022 IRP Preferred Resource Portfolio and Short Term Action Plan which include the Petersburg Repowering remains consistent with the IRP and reasonable. Further, the Commission's rules allow updated analysis.[24]

Q47. Has the IURC's Director reviewed the 2022 IRP and issued a report?

A47. Yes. The Director has issued a draft report where he gives his comments on the IRP analysis and other stakeholder comments on the IRP analysis. At the time of filing this rebuttal, the Director had not issued a final report.

Q48. Does the Director's draft report support REI's view that AES Indiana's 2022 IRP is flawed?

A48. No. There were no major issues. His comments were helpful to consider as improvements to future IRPs. Regarding AES Indiana's Scorecard evaluation of the Five Pillars conducted in the 2022 IRP, the Director states –

"As described above, the portfolio metrics and scorecard were explicitly based on the Five Pillars of reliability, affordability resiliency, stability, and environmental sustainability. The discussion of the metrics and the scorecard results were well done and

[24] 170 IAC 4-7-2.5 (b), also 10(a)

very helpful. Understanding how AES Indiana interpreted and applied the results is critical." p.18

And "…AES Indiana provided an excellent discussion of the modeling results and the key takeaways as the modeling progressed. The discussion of the scorecard evaluation results in section 9.4 of the IRP report (IRP pages 234-252) was informative and helped the Director to understand how AES Indiana interpreted and used the different modeling results to inform AES Indiana's selection of the preferred portfolio." p.19

Ms. Medine may disagree with the assumptions and input used in the 2022 IRP, but as the Company's testimony demonstrates, our assumptions and inputs were reasonable and unbiased. Her disagreement in no way establishes that the IRP is flawed.

Q49. REI witness Medine (p. 31) indicates that AES Indiana has not discussed upstream emissions from natural gas in considering the Sustainability Pillar. Please respond.

A49. In evaluating the Sustainability Pillar, AES Indiana did not capture upstream emissions when calculating the total emissions for each of the Petersburg strategies in the 2022 IRP and 2024 IRP Update. The Company limited the analysis to only "inside the fence" emissions or emissions directly associated with combustion processes and power production at the plants because they are difficult to quantify and open the door for contention among stakeholders.

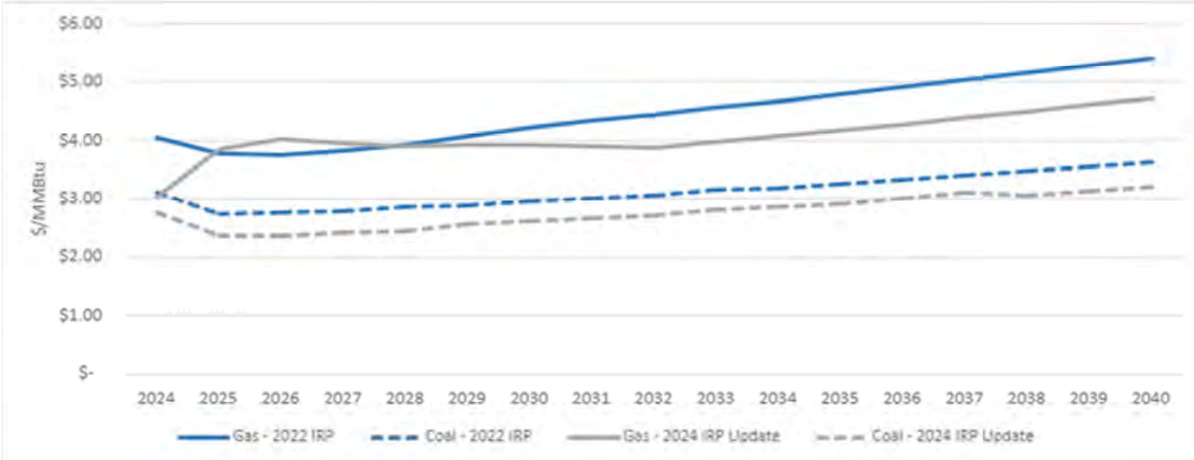
Also, by suggesting that AES Indiana include upstream emissions associated with natural gas power production, Ms. Medine is trying to make the Petersburg Repowering look worse from a Sustainability perspective. However, she needs to keep in mind that if AES Indiana were to include upstream emissions for power production using natural gas, then the Company would also have to include them for power production using coal thereby also negatively impacting the strategy that she prefers

Q50. REI witness Medine (p. 31) alleges the capacity factor shown in Figure 13 of AES Indiana witness Miller's Direct Testimony demonstrates that the Petersburg on coal is more economic than repowering the units because Petersburg on coal has a higher capacity factor. How do you respond?

A50. I disagree. Ms. Medine is basing her assessment on only the energy revenue generated from coal operation versus natural gas operation and is thereby failing to see the whole picture. To explain, the capacity factor of the units (shown in the chart that she references) provides an approximation of, not only emissions, but the energy revenue generated by the units. The energy revenue is driven by the commodity curves included in the analysis. In this case, coal has economics that support more operation versus natural gas over the planning period, i.e. the units are "in the money" more of the time.

To help illustrate this, Figure 7 provides a comparison of the coal price versus the gas prices on a per MMBtu basis included in the 2024 IRP Update. The chart demonstrates that the analysis included higher natural gas prices compared to coal prices thereby driving more coal-fired operation. Thus, with lower prices available, Petersburg operating on coal generates more energy revenue over the planning period versus operating the units on natural gas. Figure 7 also demonstrates that AES Indiana had no intention of biasing the analysis with uncharacteristically high coal prices and low natural gas prices as Ms. Medine has also claimed.

Figure 7. 2022 IRP and 2024 IRP Update Natural Gas and Coal Price Forecast Comparisons



Most importantly, **energy revenues alone do not tell the full story**. The primary cost savings to AES Indiana customers come from the fixed O&M savings that result from repowering the units. Operating the units on coal requires additional fixed O&M costs associated with coal handling and coal emissions equipment all of which are eliminated when the units are repowered. Figure 9 in my Direct Testimony provides a complete picture of the various costs and benefits of repowering the units. The Figure demonstrates both the fixed O&M and energy revenue impacts associated with repowering the units. In summary, we are not making the decision to repower the units based on energy revenues alone. The PVRR provides the complete picture and represents the estimated cost of the Petersburg strategies to customers.

6. THIRD PARTY SALE

Q51. REI witness Medine indicates that AES Indiana failed to consider the sale of Petersburg as part of its IRP analysis. She indicates that the reason given in the Company's Direct Testimony for not selling the units was because "it would put the company at risk on capacity prices ignoring the option of a PPA." How do you respond?

A51. I believe Ms. Medine is referencing Q/A 40 in my Direct Testimony.[25] The point I was making in my Direct Testimony was simply that AES Indiana would not rely on the MISO market transactions for 1,000 MW worth of capacity to replace Petersburg. Doing so would put the Company and its customers at significant risk of market price volatility and perhaps reliability issues. In addition, this would be at odds with Ind. Code 8-1-8.5-13, which requires utilities to enter the annual MISO Planning Resource Auction ("PRA") with a deficit of no more than 15% of their Planning Reserve Margin Requirement. Relying on the MISO market in a significant way over the long term is simply not a tenable solution.

If the Company were to sell the Petersburg Units, we would have to replace that capacity by either constructing new resources or entering into a PPA for capacity and energy. The contention that the Company should sell this facility to a third party fails to recognize the value of the Petersburg location to AES Indiana and its customers due to the asset, land and interconnection value at the location. Additionally, AES Indiana intends to continue to support the Petersburg community where the Company has had a presence since 1967. Please see AES Indiana witnesses Bigalbal (Section 4) and Witness Cooper's Rebuttal

[25] The footnote reference that Witness Medine provides on p. 14, footnote 15 in her testimony is incorrect. This footnote should reference Q/A 40 in Witness Miller's Direct Testimony.

Testimony (Q/A 23 and 24) for more response to Ms. Medine's interest in selling the Petersburg Units.

7. FIVE PILLARS

Q52. Does the OUCC raise any concerns regarding the AES Indiana's Affordability analysis in its 2022 IRP?

A52. No. OUCC witness Latham states (p. 6), "After considering the costs and benefits of the Project, particularly after recovery of the deferred amounts, the OUCC does not have concerns about the Project's affordability at this time."

Q53. Please summarize REI witness Medine's position on the affordability pillar.

A53. Ms. Medine asserts (p. 16) that, according to Indiana Code 8-1-2-0.6, affordability should not be determined by relative net present value ("NPV") calculations, like those used in the IRP, because the NPV analysis does not consider whether rates are affordable across all classes. She claims that AES provides a superficial analysis of residential rates because the NPV does not account for "sunk costs" associated with early retirements nor does it contain a rate impact analysis. I address her concerns below.

Q54. Do you agree with REI witness Medine's overarching claim (p. 16-17) that AES Indiana's consideration of affordability in its 2022 IRP and 2024 IRP Update is not consistent with Indiana Code 8-1-2-0.6?

A54. No. Indiana Code 8-1-2-0.6 does not specifically require that Ms. Medine's "full rate impact" analysis be performed as part of an IRP. The NPV (PVRR) analysis performed in the 2022 IRP and 2024 IRP Update provides a robust assessment of the general impact to residential, commercial and industrial customers. How the PVRR is ultimately allocated at the class level from the implementation of a project is a ratemaking exercise performed as part of a general rate case. AES Indiana witness Rogers performed a rate impact analysis in his Direct Testimony[26] and further replies to REI's concerns with AES Indiana's analysis of Affordability.

Q55. Please elaborate on your response to REI witness Medine's claim (p. 14) that "the statue [sic] itself is clear that an affordability analysis should consider rate impacts on all customer groups."

A55. AES Indiana complied with the IURC requirements for measuring the cost to customers as identified in the IURC rules in conducting the Company's IRP. The rules require that "The present value of revenue requirement for each candidate resource portfolio in dollars per kilowatt-hour delivered, with the interest rate specified." (IAC 4-7-8 (a)(3)) The Company discusses the affordability results and presents the PVRR in this manner on pp. 184-186 of the 2022 IRP.

REI raised this issue in their comments to AES Indiana's 2022 IRP. The Director responded to their comments in his Comments to AES Indiana's 2022 IRP (see p. 24). In his response to REI, the Director says,

> *As discussed earlier, the Director understands the difficulty of evaluating the affordability of different resource plans over a 20-year planning horizon. The cumulative NPVRR of a portfolio over the planning horizon is informative but does have limitations. One being that the difference between the candidate portfolios is often only a few percentage points. A useful complement is to show the annual revenue requirement of a candidate portfolio for each year of the planning period, both in nominal dollars and real dollars. This was done by AES Indiana using nominal dollars."*

[26] AES Indiana witness Rogers' Direct Testimony at Q/A 39 and AES Indiana Attachment CAR-2 and -2(C), lines 57-63.

Overall, the Director expressed no concern with the Affordability analysis that AES Indiana performed in the IRP. In fact, he is complimentary of the discussion of the IRP Scorecard and Affordability provided by AES Indiana in its IRP (see Q/A 23 above).

Q56. Please elaborate on your statement that the statute does not specifically require that Ms. Medine's "full rate impact" analysis be performed as part of an IRP

A56. The statute does not require the "full rate impact" analysis be performed as part of an IRP. Rather, the statute provides "it is the continuing policy of the state that decisions concerning Indiana's electric generation resource mix, energy infrastructure, and electric service ratemaking constructs must consider each of the [enumerated] attributes of electric utility service" including affordability, which the statute describes as follows:

> (2) Affordability, including ratemaking constructs that result in retail electric utility service that is affordable and competitive across residential, commercial, and industrial customer classes.

The statutory pillar stems from the Indiana 21st Century Task Force. The October 2022 Task Force Report describes the affordability pillar as follows:

> (4) Affordability: Reliable, resilient, and stable electricity is an essential service for Indiana residents, businesses, and manufacturers. Decisions regarding Indiana's generation resource mix and ratemaking constructs must result in retail electric service that is affordable across the residential, commercial, and industrial customer classes.[27]

This report further describe Affordability as follows:

> (16) Any consideration of the state's energy policy, or any statutory changes affecting the state's energy policy, should take into account the policy stated in IC 8-1-2-0.5: The general assembly declares that it is the continuing policy of the state, in cooperation with local governments and other concerned public and private organizations, to use all practicable means and measures, including

[27] DRAFT 21st Century Task Force report.pdf (ipbs.org), p. 8.

financial and technical assistance, in a manner calculated to create and maintain conditions under which utilities plan for and invest in infrastructure necessary for operation and maintenance while protecting the affordability of utility services for present and future generations of Indiana citizens.

(17) Customer assistance programs, such as the Low-Income Home Energy Assistance Program (LIHEAP) and the Weatherization Assistance Program (WAP), are important resources to help low-income customers afford their energy bills, especially during the winter heating season. In addition, utility-sponsored energy efficiency programs enable customers to take advantage of opportunities to reduce their overall bill. Together, customer assistance programs and energy efficiency programs can assist customers, particularly low-income customers, and mitigate the financial impacts of higher energy prices.

(18) The ability to draw power from multiple types of resources as part of a diverse generation resource mix allows for the mitigation of price volatility and serves as a hedge against constraints, such as those involving fuel supplies and supply chains, and against other potential future disruptions in supply.

(19) In an ever-changing energy landscape, Indiana's regulatory framework should allow the opportunity for innovation and flexibility to ensure Indiana utilities can act in a timely manner for the benefit of their customers. To that end, the General Assembly and the IURC should continue to improve procedural efficiencies through multiple pathways and opportunities, without compromising the five pillars.

(20) The increased use of intermittent generation resources is dependent on a significant expansion of the existing electric transmission system. Additionally, with Indiana's location on or near several key seams between transmission planning regions, it is expected that more land will be used to host the growth of transmission systems, making Indiana the “Crossroads of America” for more than just roads. Given these realities, it is important that state regulators and policymakers closely monitor the impact that transmission investments can have on local communities, along with the upward pressure such investments can impose on utility rates.

(21) The affordability of electricity has become a more important concern because electricity prices in Indiana are no longer, as they once were, among the lowest of the fifty (50) states.

Q57. REI witness Medine (p. 20) claims that AES Indiana's omitted "knowable expenses" largely related to the firm transportation of natural gas in the Company's Affordability analysis performed for the 2022 IRP and 2024 IRP Update. Is this claim accurate?

A57. No. AES Indiana included approximately $10.6 million per year or $191 million in nominal dollars over the planning period as a fixed O&M cost for the firm transportation of natural gas to the repowered Petersburg units. During the 2022 IRP process and as part of the workpapers submitted in this filing, AES Indiana was fully transparent in providing documents related to the IRP analyses and its associated inputs.[28] Ms. Medine had access to the supporting documents to confirm that firm natural gas transportation was included in the analysis. These firm natural gas transportation costs also were included in AES Indiana witness Rogers' rate impact analysis. See Q/A 39 of his Direct Testimony.

Q58. Turning now to the Reliability, Resiliency, and Stability Pillars, REI witness Medine (p. 20) claims that the 2022 IRP and 2024 IRP Update failed to capture reliability, resiliency and stability issues related to not having arranged for "firm transportation of natural gas [for the repowered Petersburg Units] that will withstand severe weather and force majeure events." How do you respond to this claim?

A58. First, AES Indiana has arranged for firm natural gas transportation for the Petersburg Units and the approximate costs for this gas transportation were included in the 2022 IRP and 2024 IRP Update. See AES Indiana witness Cooper's Direct (Q/A 15) and Rebuttal (Q/A 16) Testimony for further discussion. Second, force majeure events affect coal

[28] See Confidential Workpaper Witness EKM-2 on the Pete 3 Updated and Pete 4 Updated tabs, Row 18.

units as well as natural gas units. This is evident when coal piles freeze in winter storm events. See AES Indiana witness Cooper Rebuttal (Q/A 19) for more discussion of reliability issues associated with coal plant operation. In the Reliability Analysis performed for the 2022 IRP, Quanta adequately captured potential reliability-related issues for both coal and natural gas operation at Petersburg in the forced outage assumptions included for the units in both strategies. Consequently, it was not necessary to update the Quanta Reliability analysis. REI's witnesses identify no credible basis to conclude otherwise.

Q59. REI witness Medine suggests (pp. 20-23) that force majeure events at natural gas facilities could be avoided by adding dual-fuel capability or mini-LNG plants to create onsite inventory at Petersburg. She indicates that these costs were not included in AES Indiana's analysis. Please respond.

A59. I disagree. AES Indiana has adequately arranged for firm gas transportation for these units once they are converted. These costs were modeled in the 2022 IRP and 2024 IRP Update. AES Indiana witness Cooper discusses (pp. 8-10) the operational reliability of the repowered units in his Rebuttal Testimony. As his testimony demonstrates, these units will be operationally reliable without the need for dual-fuel capability or onsite LNG backup. As such, additional costs for these options were not included in the 2022 IRP and 2024 IRP Update.

8. STATEWIDE ENERGY PLAN

Q60. REI Witness Nasi (pp. 18-19) claims that AES Indiana has failed to meet the requirements of the CPCN statute (Ind. Code ch. 8-1-8.5) because AES Indiana has failed to demonstrate that its proposal is consistent with the Commission's Statewide Energy Plan. Is he correct?

A60. No, he is not correct. Ind. Code 8-1-8.5-5(b) clearly states one of the findings the Commission must make before granting a "certificate of need" is that the proposed project is consistent with either the Commission's statewide generation expansion analysis ("Statewide Analysis"), or the utility's current integrated resource plan.

Q61. Has the Commission previously weighed in on Mr. Nasi's argument that a utility seeking a CPCN for a generating facility must demonstrate that its proposal is consistent with the Commission's Statewide Analysis?

A61. Yes, the Commission addressed this same argument in Cause No. 45052, a SIGECO CPCN case. In that case, the Commission found that "the statute is clear that in considering a CPCN request, pursuant to Section 5(b)(2) we can rely on whatever current statewide analysis exists ***or*** simply determine whether the proposal is consistent with the utility's own plan and reports." [29]

Q62. To your knowledge, has the Commission developed a Statewide Analysis for the expansion of electric generating capacity?

[29] *In re Verified Petition of SIGECO*, Cause No. 45052 (IURC; Apr. 24, 2019), p. 19 (emphasis added).

A62. To my knowledge, the last time the Commission developed and published such a Statewide Analysis was in 2018.[30] Notably, in that 2018 Statewide Analysis, the Commission emphasized "the Statewide Analysis is not to be construed as a statewide energy plan and does not set policy. In addition, the Statewide Analysis does not determine or predetermine individual electric resource decisions or Commission findings and conclusions in any pending or future proceeding before the Commission." [31]

Q63. In your view, are there any elements of the Commission's 2018 Statewide Analysis which are relevant to this proceeding?

A63. In general, I would note that with the passage of time, a number of inputs have changed – perhaps most notably in the area of increased load growth projections since 2018. I would also note that the 2018 Statewide Analysis generally aggregates the specific utility's most recent IRPs (2018 Statewide Analysis, at p. 6), which highlights the reasonableness of a utility relying on its own IRP to support a CPCN proposal. Notwithstanding the passage of time and changes in various inputs, the 2018 Statewide Analysis generally supports AES Indiana's proposal to repower Petersburg Units 3 and 4, in the following ways:

- The 2018 Statewide Analysis projects the need for significant additional generation in Indiana to replace retired coal-fired units and maintain reliability;[32]
- The 2018 Statewide Analysis projects the increased use of gas-fired generation in Indiana and by AES Indiana;[33] and
- The 2018 Statewide Analysis contemplates the cessation of coal-fired generation at Petersburg Units 3 and 4 and the potential repowering of such units.[34]

[30] *See* https://www.in.gov/iurc/files/2018-Report-on-the-Statewide-Analysis-of-Future-Resource-Requirements-for-Electricity.pdf.
[31] *See 2018 Report on the Statewide Analysis of Future Resource Requirements for Electricity ("2018 Statewide Analysis),* at p. 1.

[32] *Id.* at p. 22.
[33] *Id.* at pp. 23-39.

9. CONCLUSION

Q64. Please summarize your testimony, conclusions and recommendations.

A64. AES Indiana appreciates the input provided by stakeholders in this CPCN filing and throughout the IRP process. I found the OUCC's testimony to be thoughtful, and well-researched. In considering the REI witness challenges to the Petersburg Repowering, it is reasonable to recognize that REI has a self-interest in keeping utilities burning coal. If coal generation continues in Indiana, then REI benefits from the continued sale of coal and coal plant purchases. To that end, the bulk of the REI witness testimony focuses on creating uncertainty regarding the benefits of repowering the Petersburg units to gas.

Regardless, through AES Indiana's IRP process and the analysis performed for this CPCN proceeding, the Company has demonstrated that the Petersburg Repowering reasonably balances affordability, reliability, and sustainability for its customers. The Company has reasonably considered and evaluated the required options for providing reliable, efficient, and economic service. AES Indiana bears the service obligations and should be given some discretion to exercise its reasonable judgment in selecting the resource(s). The proposed repowering minimizes the cost of providing service as discussed in the Company's direct and rebuttal testimony. I recommend that the Commission approve the repowering of the Petersburg units as requested by the Company.

Q65. Does this conclude your prefiled rebuttal testimony?

A65. Yes, it does.

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[34] *Id.* at p. 26.

VERIFICATION

I, Erik K. Miller, Director, Resource Planning for AES Indiana, affirm under penalties for perjury that the foregoing representations are true to the best of my knowledge, information, and belief.

Dated June 26, 2024

Erik K. Miller

Data Request REI DR 2 - 1

Referring to witness Miller's direct testimony at page 33, lines 3-18, please produce all inputs, costs, calculations, analyses and assessments that Mr. Miller performed or relied upon to support Mr. Miller's conclusion that "…keeping Petersburg on coal would require excessive costs for CCS."

Objection: AES Indiana objects to the Request on the grounds and to the extent it is overly broad and unduly burdensome. AES Indiana further objects to the Request on the grounds and to the extent it solicits information that has been previously provided. AES Indiana further 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. 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:

At the time of filing its direct testimony in this Cause, AES Indiana assessed that the cost of compliance with the rules proposed by the EPA would only add cost to keeping Petersburg Units 3 and 4 as a coal-burning resource by requiring carbon capture and sequestration ("CCS"). Under the new EPA rules, AES Indiana would not be required to implement CCS and incur the corresponding costs for customers when it repowers the units using natural gas. This would only increase the PVRR of the strategy continues to use coal at Petersburg relative to the other strategies evaluated in the 2024 IRP Update, which includes converting Petersburg Units 3 and 4 to burn natural gas.

Data Request REI DR 2 - 2

Please produce any analysis, assessment, calculation, or investigation that AES performed to identify the estimated costs of options for AES to comply with the recently published "New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units" issued by the Environmental Protection Agency ("EPA") on May 9, 2024 at 89 Fed. Reg. 38,798 (hereinafter "Final 111 Carbon Rule") assuming that the Petersburg units 3 and 4 coal facilities remain operational.

Objection: AES Indiana further 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. Subject to and without waiver of the foregoing objections, AES Indiana provides the following response.

Response:
See below from excerpt from Response to OUCC DR 3-1:

> If AES Indiana were to continue to operate Units 3 and 4 as coal-fired after January 1, 2032, emissions reductions of 16% as compared to baseline emissions could be required, consistent with application of 40% natural gas co-firing, resulting in capital investment. If Units 3 and 4 continued to operate as coal-fired after January 1, 2039, emissions reductions of 88.4% compared to baseline emissions could be required, consistent with application of carbon capture sequestration, likely resulting in significant capital investment.

In light of the recently published EPA rules ("New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units" issued by the Environmental Protection Agency ("EPA") on May 9, 2024 at 89 Fed. Reg. 38,798), AES Indiana has estimated the impacts for compliance with these rules in the strategies analyzed in the 2024 IRP Update. The following paragraphs summarize the assumption updates made to capture compliance with the EPA rules in the 2024 IRP Update and concludes with the results from the analysis.

Across all strategies in the 2024 IRP Update, the Company updated two core modeling assumptions. 1) To avoid double counting the impact of carbon regulation, AES Indiana removed the carbon price of $6.50 starting in 2028. This carbon price was originally intended to serve as a proxy for regulation of carbon like the finalized EPA rules. 2) The Company updated the commodities to better align with a future that includes the finalized EPA rules. AES Indiana used Horizons Fall 2023 Zero Carbon Additions commodities. According to Horizons, this set of commodities most closely represents power, gas, and coal prices in a future with the finalized EPA rules.

In the strategy that keeps Petersburg Units 3 & 4 on coal for the planning period, the Company assumed these units would be required to converted to co-fire with 40% natural gas by Jan. 1, 2030 to comply. The co-firing conversion cost was estimated to be 65% of the cost of the full conversion. The appropriate mix of fuel and variable O&M which assumes co-firing the units with natural gas was also modeled in the analysis. These co-fired units were assumed to remain operational through the planning period or through 2042. However, per the EPA rules, these units would either have to retire by 2039 or install CCS by 2032. Either of these options would only make continuing to operate Petersburg as a partly coal-fired asset less cost effective by adding cost for CCS or the cost for replacement resources upon retirement.

Operating Petersburg Units 3 & 4 as natural gas-fired resources starting in 2026 (the request being made in this filing) will largely be unaffected operationally by the EPA rules. As such, in the strategy that converts Petersburg Units 3 & 4 to operate on natural gas, the units were assumed to operate consistent with the operational parameters of the original 2024 IRP Update included in this filing. Also, the strategies that retire and replace Petersburg Units 3 & 4 with other resources were unaffected by compliance with the EPA rules since both strategies replace the units with wind, solar and storage resources.

The table below provides the results of this analysis. The Petersburg Conversion is now $437 million lower in terms of PVRR over the planning period than keeping Petersburg a coal co-fired with gas resource. Also note that the "No Early Retirement" strategy assumes Petersburg Units 3 & 4 operate as a co-fired 40% natural gas and 60% coal resource to comply with the new EPA rule through 2039 and continues through the planning period. Per the EPA rules, either CCS would need to be installed on these units in 2032 or they would need to be retired by 2039. Compliance with either of these options would only make the units less cost effective from a PVRR perspective.

2024 IRP Update with cost for EPA rules compliance ($M)

	2022 IRP 20-yr PVRR ($M)	2024 IRP Update ($M)	2024 IRP Update w/ EPA Rule Compliance ($M)	Reliability Costs ($M)	2024 IRP Update with Reliability Cost ($M)	2024 IRP Update w/ EPA Rule Compliance and Reliability Cost ($M)
No Early Retirement (Units Co-fired with 40% NG by 2030 through analysis period)*	$ 9,572	$ 9,449	$ 9,192	$ 126	$ 9,575	$ 9,318
Petersburg Conversion to Natural Gas (est. 2026)	$ 9,330	$ 9,168	$ 8,745	$ 136	$ 9,304	$ 8,881
Both Petersburg Units Retire (2027 and 2029)	$ 9,618	$ 9,596	$ 9,343	$ 929	$ 10,525	$ 10,272
Clean Energy Strategy - Both Petersburg Units Retire and Replaced with Wind, Solar and Storage (2027 and 2029)	$ 9,711	$ 9,604	$ 9,352	$ 929	$ 10,533	$ 10,281

Data Request REI DR 2 - 3

Please produce any analysis, assessment, calculation or investigation that AES performed to determine whether the repowered Petersburg natural gas units will be treated as an "affected source" under the Final 111 Carbon Rule, as well as the proposed version of that rule (88 Fed. Reg. 33,240 (May 23, 2023) (hereinafter, "Proposed 111 Carbon Rule").

Objection:

Response:

Pursuant to 40 CFR 60.5880b of the final Emissions Guidelines for Greenhouse Gas Emissions for Electric Utility Generating Units, published in the Federal Register on May 9, 2024, an affected electric generating unit (EGU) is a steam generating unit[1] that meets the relevant applicability conditions in 40 CFR 60.5845b. 40 CFR 60.5845b(b) provides that an affected EGU is a steam generating unit that serves a generator capable of selling greater than 25 MW to a utility power distribution system and that has a base load rating of greater than 250 MMBtu/hr heat input of fossil fuel.[2] Petersburg Units 3 and 4 meet these conditions. Certain EGUs are excluded from being an affected EGU as specified in 40 CFR 60.5850b; however, Petersburg Units 3 and 4 do not meet any of the listed exclusions. Finally, 40 CFR 60.5845b(a) provides that State plans must address affected EGUs that were in operation or had commenced construction on or before January 8, 2014, which is the case for Petersburg Units 3 and 4. As such, Petersburg Units 3 and 4 are affected EGUs under 40 CFR 60, Subpart UUUUb, Emissions Guidelines for Greenhouse Gas Emissions for Electric Utility Generating Units and IDEM will be required to develop a State Plan which must address Petersburg Units 3 and 4.

The proposed version of the Emissions Guidelines for Greenhouse Gas Emissions for Electric Utility Generating Units contained consistent applicability criteria relevant to Petersburg Units 3 and 4.

[1] Per 40 CFR 60.5880b, a "steam generating unit means any furnace, boiler, or other device used for combusting fuel and producing steam (nuclear steam generators are not included) plus any integrated equipment that provides electricity or useful thermal output to the affected facility or auxiliary equipment."
[2] Per 40 CFR 60.5880b, "Fossil fuel means natural gas, petroleum, coal, and any form of solid fuel, liquid fuel, or gaseous fuel derived from such material for the purpose of creating useful heat."

Data Request REI DR 2 - 4

Which provisions and/or subcategories of the Proposed 111 Carbon Rule and the Final 111 Carbon Rule apply to the proposed Petersburg repowered natural gas units? Please produce any analyses, assessments, calculations, or investigation that AES performed supporting this determination.

Objection:

Response: Petersburg Units 3 and 4 upon repowering to natural gas are expected to fall into the following subcategories:

- 40 CFR 60.5740b(a)(1)(vi): *Base load natural gas-fired steam generating units*, consisting of natural gas-fired steam generating units with an annual capacity factor greater than or equal to 45 percent; and/or
- 40 CFR 60.5740b(a)(1)(vii): *Intermediate load natural gas-fired steam generating units*, consisting of natural gas-fired steam generating units with an annual capacity factor greater than or equal to 8 percent and less than 45 percent.

Under the proposed rule, Petersburg Units 3 and 4 upon repowering to natural gas would have been expected to fall into the same subcategories, proposed to be codified as 40 CFR 60.5740b(a)(1)(I) and (J).

Data Request REI DR 2 - 5

Please produce any analyses, assessments, calculations, or investigation that AES performed to determine the technological and economic feasibility of complying with the Proposed 111 Carbon Rule as well as the Final 111 Carbon Rule.

Objection:

Response: See <u>REI DR 2-5 Attachment 1</u> for the analysis from Sargent & Lundy dated May 2, 2024.

Sargent & Lundy

Wayshalee A. Patel
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May 2, 2024

Mr. Mark Siner
Contract Lead Engineer – AES US Services LLC
mark.siner@aes.com

Dear Mr. Siner:

AES requested Sargent & Lundy (S&L) to opine on the impact of the New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emissions Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule, hereafter referred to as 'GHG Rule', to the Petersburg Units 3 and 4 coal-to-gas conversion CO_2 emissions.

AES Indiana is in the process of repowering Units 3 & 4 at the Petersburg Generating Station to natural gas. Babcock & Wilcox (B&W) has been awarded the Engineering, Procurement, & Construction contract for the conversion of these units from coal to gas and provided the estimated CO_2 emissions at the three load conditions shown in Table 1 below.

Table 1: Estimated CO_2 Emissions on Natural Gas Firing	
	CO_2 Emissions (lb/hr)
Petersburg Unit 3	
100% MCR (580 MWg)	725,000
60% MCR (348 MWg)	442,000
30% MCR (174 MWg)	224,000
Petersburg Unit 4	
100% MCR (572 MWg)	726,000
60% MCR (343 MWg)	445,000
30% MCR (172 MWg)	228,000

S&L calculated the estimated emission rate of CO_2 in lb/MWhg using the emissions provided in Table 1 above and the MWh generation of each unit. The results are provided in Table 2 below.

Table 2: Estimated CO_2 Emissions (lb/MWhg) on Natural Gas Firing	
	CO_2 Emissions (lb/MWhg)
Petersburg Unit 3	
100% MCR (580 MWg)	1,250
60% MCR (348 MWg)	1,270
30% MCR (174 MWg)	1,287
Petersburg Unit 4	
100% MCR (572 MWg)	1,269
60% MCR (343 MWg)	1,297
30% MCR (172 MWg)	1,329

The GHG rule is based on achieving efficiency-based CO_2 emissions limitations based on the source category and annual capacity factor threshold. The CO_2 emission standards for each source category are shown in Table 3 below.

Table 3: Gas-Fired Steam EGU Emission Standards		
Source Category	**Annual Capacity Factor Threshold**	**Emission Standard**
Low Load	< 8%	130 lb CO_2/MMBtu
Intermediate Load	>8% but <45%	1,600 lb CO_2/MWhg
Base Load	>45%	1,400 lb CO_2/MWhg

Per discussion with AES, the Petersburg units are not anticipated to operate in the low load subcategory and therefore have not been evaluated. For the remaining subcategories, the estimated CO_2 emissions for the Petersburg Units from Table 2 range between 1,250-1,329 lb CO_2/MWhg, in comparison to the emission standards at the intermediate and base load categories in Table 3, 1,400-1,600 lb CO_2/MWhg. As such, based on the information provided, S&L confirms that Petersburg units should be in compliance with the GHG Rule after the coal-to-gas conversion.

Best Regards,

Wayshalee A. Patel

Wayshalee A. Patel
Discipline Manager Environmental Technologies,
Licensing and Permitting

Data Request REI DR 2 - 6

Referring to witness Collier's direct testimony at page 13, lines 9-10 that "[u]pon repowering to natural gas, Petersburg Units 3 and 4 would be existing natural gas-fired EGUs," and assuming the repowered natural gas units were to be treated as an existing source under the Final 111 Carbon Rule, please produce any analysis, assessments, calculation or investigation that AES performed to identify the compliance requirements and related costs associated with the Final 111 Carbon Rule.

Objection:

Response:

See the Company's response to REI DR 2-5 and below excerpt from the Company's response to OUCC DR 3-1:

Witness Collier's direct testimony, page 13, lines 9-14 states:

> Upon repowering to natural gas, Petersburg Units 3 and 4 would be existing natural gas-fired EGUs under the proposed rule. As such, based on the proposed rule, the repowered Units 3 and 4 would be subject to an emissions limit based on routine methods of operation and maintenance.
>
> The requirements of a final CAA Section 111(d) rule, and the results of any associated legal challenges, remain uncertain. EPA may issue a final rule in early 2024.

The 2023 proposed Greenhouse Gas New Source Performance Standards under CAA Section 111(d) discussed in direct testimony identified in the Request (Collier, page 13, lines 9-12) would require states to develop State Plans establishing standards of performance for electric generating units based on EPA's emissions guidelines. Under the 2023 proposal, this would include Petersburg Units 3 and 4 as existing natural gas-fired EGUs. As such, specific requirements for Petersburg Units 3 and 4 would be established through the state rulemaking process with a State Plan due within 24 months of a final EPA Section 111(d) rule and with a possible compliance deadline of January 1, 2030. Although a proposed State Plan has not yet been developed, EPA's proposed 2023 emissions guidelines for existing natural-gas fired EGUs is based on routine methods of operation and maintenance, which would occur through normal operational processes and would not be expected to impact the projected life of the plant.

On April 25, 2024, EPA released a pre-publication version of its final rules regulating greenhouse gas emissions from electric generating units under Section 111 of the Clean Air Act. The regulation being finalized under Section 111(d) of the Clean Air Act, at 40 CFR 60, Subpart UUUUb, would require states with affected existing coal-fired and existing natural gas-fired steam generating electric generating units (EGUs) (i.e., electric utility boilers) to submit State Plans to EPA for approval. State Plans must include standards of performance (i.e., emissions limitations) for each affected existing unit in the state based on EPA's determined Best System of Emissions Reductions (BSER) for the particular type of unit. An existing unit is one that commenced construction on or before January 8, 2014[3]. An EGU is considered to be coal-fired if it combusts, or is capable of combusting, coal on or after January 1, 2030[4]. A unit is considered to be natural gas-fired if it combusts natural gas, and no longer retains the capability to fire coal, on and after January 1, 2030[5]. EPA is establishing presumptively approvable standards of performance for states to use in establishing emissions limitations in their State Plans. However, states may apply less stringent, in some circumstances[6], or more stringent emissions limitations than the presumptively approvable standards.

For existing coal-fired affected EGUs, EPA is finalizing Emissions Guidelines based on the timeframe for expected continued coal combustion. Coal-fired affected EGUs that commit to cease coal combustion prior to January 1, 2032, are not subject to emissions limitations. Coal-fired affected EGUs that plan to cease coal combustion after January 1, 2032 and before January 1, 2039 are subject to Emissions Guidelines based on 40% natural gas co-firing with a presumptively approvable standard of 16% reduction in emissions rate compared to a unit-specific baseline with compliance required starting for calendar year 2030. Coal-fired affected EGUs that plan to operate after January 1, 2039 are subject to Emissions Guidelines based on 90% carbon capture and sequestration with a presumptively approvable standard of 88.4% reduction in

[3] 40 CFR 60.5845b(a)(1)
[4] 40 CFR 60.5880b: "*Coal-fired steam generating unit* means an electric utility steam generating unit or IGCC unit that meets the definition of "fossil fuel-fired" and that burns coal for more than 10.0 percent of the average annual heat input during any continuous 3-calendar-year period after December 31, 2029, or that retains the capability to fire coal after December 31, 2029."
[5] 40 CFR 60.5880b: "*Natural gas-fired steam generating unit* means an electric utility steam generating unit meeting the definition of "fossil fuel-fired," that is not a coal-fired or oil-fired steam generating unit, that no longer retains the capability to fire coal after December 31, 2029, and that burns natural gas for more than 10.0 percent of the average annual heat input during any continuous 3-calendar-year period after December 31, 2029, or for more than 15.0 percent of the annual heat input during any calendar year after December 31, 2029."
[6] Based on remaining useful life and other factors as described in 40 CFR 60.5775b(j).

emissions rate compared to a unit-specific baseline with compliance required starting for calendar year 2032.

For existing natural gas-fired affected EGUs, EPA is finalizing Emissions Guidelines based on load type with compliance required starting for calendar year 2030. Low load affected EGUs[7] are subject to Emissions Guidelines based on use of uniform fuels with a presumptively approvable emissions limit of 130 pounds CO_2 per million Btu (lb CO_2/MMBtu). Intermediate load EGUs[8] are subject to Emissions Guidelines based on routine methods of operation and maintenance with a presumptively approvable emissions limit of 1,600 pounds per megawatt hour (gross) (lb/MWh-gross). Base load EGUs[9] are also subject to Emissions Guidelines based on routine methods of operation and maintenance, but with a presumptively approvable emissions limit of 1,400 lb/MWh-gross.

[7] Low load EGUs are those with a capacity factor less than 8%.
[8] Intermediate load EGUs are those with a capacity factor of 8 to 45%.
[9] Base load EGUs are those with a capacity factor greater than or equal to 45%.

Data Request REI DR 2 - 7

Assuming the repowered Petersburg natural gas units were to be treated as an existing source under the Final 111 Carbon Rule and in light of EPA's announcement that it intends to regulate existing natural gas power plants in a separate rulemaking that is currently under consideration in non-regulatory docket EPA-HQ-OAR-2024-0135 (hereinafter "EPA-Planned Existing Natural Gas Carbon Rule"), please produce any analysis, assessments, calculation or investigation that AES performed to identify the compliance requirements and related costs associated with potential outcomes of that rule in light of the approach taken by EPA in the Proposed 111 Carbon Rule as it relates to existing natural gas power plants.

Objection:

Response:

The non-rulemaking docket EPA-HR-OAR-2024-00135 is related to emissions of greenhouse gases from existing fossil fuel-fired stationary combustion turbines. Petersburg Units 3 and 4 are not stationary combustion turbines.[10] Rather, Petersburg Units 3 and 4 are steam generating units.[11] As such, Petersburg Unit 3 and 4 will not be affected by a future rulemaking associated with the non-rulemaking docket EPA-HR-OAR-2024-00135.

[10] Per 40 CFR 60.5880b, "stationary combustion turbine means all equipment including, but not limited to, the turbine engine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, fuel compressor, heater, and/or pump, post-combustion emission control technology, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion
turbine based system plus any integrated equipment that provides electricity or useful thermal output to
the combustion turbine engine, heat recovery system, or auxiliary equipment. Stationary means that the
combustion turbine is not self-propelled or intended to be propelled while performing its function. It may,
however, be mounted on a vehicle for portability. A stationary combustion turbine that burns any solid fuel directly is considered a steam generating unit."

[11] Per 40 CFR 60.5880b, "steam generating unit means any furnace, boiler, or other device used for combusting fuel and producing steam (nuclear steam generators are not included) plus any integrated equipment that provides electricity or useful thermal output to the affected facility or auxiliary equipment."

Data Request REI DR 2 - 8

Please produce any analyses, assessments, calculations, or investigation that AES performed to determine whether the repowered Petersburg natural gas project would be a modification as defined in 40 CFR 60.14, including any correspondence between AES and the Indiana Department of Environmental Management ("IDEM") and EPA.

Objection:

AES Indiana objects to the Request on the grounds and to the extent it solicits documents

or information already in the public domain which are accessible to Reliable Energy, Inc. Subject to and without waiver of the foregoing objections, AES Indiana provides the following

response.

Response: Correspondence between AES Indiana and IDEM is publicly available in IDEM's virtual filing cabinet: https://www.in.gov/idem/legal/public-records/virtual-file-cabinet/. Technical Support Document associated with the Significant Permit Modification (125-46458-00002)[12] and Significant Source Modification (125-46357-00002)[13] issued with IDEM and subject to EPA review[14] addresses this topic on pages 10-11 as follows [**emphasis added**]:

> (f) The requirements of the New Source Performance Standard for Greenhouse Gas Emissions for Electric Generating Units, 40 CFR 60, Subpart TTTT and 326 IAC 12, are not included in the permit for boilers Unit 3 and Unit 4, because these units were originally constructed prior to the applicability date of January 8, 2014 for this rule. However, these standards would have applied to these emission units if:
>
> > (1) the proposed project is a modification resulting in an increase in emissions of any pollutant to which a standard applies; or
> >
> > (2) the change is considered a reconstruction as defined in the NSPS rules.
>
> **The project does not qualify as a "modification" under the NSPS rules because there will not be an increase in emissions for a pollutant to which a standard applies.**

[12] https://permits.air.idem.in.gov/46458f.pdf.

[13] https://permits.air.idem.in.gov/46357f.pdf.

[14] Per 327 IAC 2-7-18 (Permit Review by the U.S. EPA), the Significant Permit Modification was submitted to EPA for review on November 13, 2023.

The proposed project does not constitute a reconstruction since the fixed capital cost of the project is less than 50% of the cost of replacing the unit with comparable units.

Since the proposed project does not constitute either modification or reconstruction, the
requirements of 40 CFR 60, Subpart TTTT do not apply to Unit 3 and Unit 4.

Data Request REI DR 2 - 9

Referring to witness Collier's direct testimony at page 13, lines 9-10 that "[u]pon repowering to natural gas, Petersburg Units 3 and 4 would be existing natural gas fired EGUs," please produce any analyses, assessments, calculation or investigation that AES performed to identify whether the repowered Petersburg natural gas project would be a reconstruction as defined in 40 CFR 60.15 and/or subject to compliance standards in Subpart TTTT, including any correspondence between AES and IDEM and EPA.

Objection:

AES Indiana objects to the Request on the grounds and to the extent it solicits documents
or information already in the public domain which are accessible to Reliable Energy, Inc. Subject to and without waiver of the foregoing objections, AES Indiana provides the following
response.

Response:

Technical Support Document associated with the Significant Permit Modification (125-46458-00002)[15] and Significant Source Modification (125-46357-00002)[16] issued with IDEM and subject to EPA review[17] addresses this topic on pages 10-11 as follows [**emphasis added**]:

> (f) The requirements of the New Source Performance Standard for Greenhouse Gas Emissions for Electric Generating Units, 40 CFR 60, Subpart TTTT and 326 IAC 12, are not included in the permit for boilers Unit 3 and Unit 4, because these units were originally constructed prior to the applicability date of January 8, 2014 for this rule. However, these standards would have applied to these emission units if:
>
> > (1) the proposed project is a modification resulting in an increase in emissions of any pollutant to which a standard applies; or
> > (2) the change is considered a reconstruction as defined in the NSPS rules.
>
> The project does not qualify as a "modification" under the NSPS rules because there will not be an increase in emissions for a pollutant to which a standard applies.

[15] https://permits.air.idem.in.gov/46458f.pdf.
[16] https://permits.air.idem.in.gov/46357f.pdf.
[17] Per 327 IAC 2-7-18 (Permit Review by the U.S. EPA), the Significant Permit Modification was submitted to EPA for review on November 13, 2023.

The proposed project does not constitute a reconstruction since the fixed capital cost of the project is less than 50% of the cost of replacing the unit with comparable units.

Since the proposed project does not constitute either modification or reconstruction, the requirements of 40 CFR 60, Subpart TTTT do not apply to Unit 3 and Unit 4.

Data Request REI DR 2 - 11

Please describe the expected heat input of each of the proposed Petersburg repowered natural gas units, and provide any analysis, assessments, calculation or investigation that AES performed to determine its ability to comply with an emission limit of 1,800 lb CO2/MWh-g or 2,000 lb CO2/MWH-g (referring to TTTT standards for reconstructed units) and the costs necessary to achieve the emission limit compliance.

Objection:

Response:
The expected heat input is 6096 MMBtu/hr for each unit. See responses to REI DRs 2-8 and 2-9. Petersburg Units 3 and 4 repowered to natural gas would not be subject to 40 CFR 60, Subpart TTTT because repowering does not constitute a modification or reconstruction of the Units.

Data Request REI DR 2 - 24

Please provide the basis in detail for the $6.50 per MWH in the response to REI DR 1-15 that the Company alleges is sufficient to support the Company's analysis of the cost of the compliance with unknown EPA regulations.

Objection:
AES Indiana objects to the Request on the grounds and to the extent it is vague and ambiguous. Subject to and without waiver of the foregoing objections, AES Indiana provides the following response.

Response:
The Company interprets the subject of this request to be EPA's GHG NSPS rules.

Please see pg. 132 of the AES Indiana 2022 IRP Volume 1 for details on the basis for the $6.50 per MWh carbon included in the 2022 IRP and the 2024 IRP Update.

As detailed in the response to REI DR 2-2, in light of the currently promulgated EPA rules, this carbon tax was removed from the 2024 IRP Update. In place of the carbon price, specific compliance measures were included in the analysis as detailed in the response to REI DR 2-2.

Data Request REI DR 2 - 25

Please admit that a carbon tax is not a compliance option under any Federal EPA air regulations for powerplants today and is not included in the final GHG rules found at: www.federalregister.gov/documents/2024/05/09/2024-09233/new-source-performance-standards-for-greenhouse-gas-emissions-from-new-modified-and-reconstructed <http://www.federalregister.gov/documents/2024/05/09/2024-09233/new-source-performance-standards-for-greenhouse-gas-emissions-from-new-modified-and-reconstructed>. If your response is anything other than an unqualified admission, please fully explain your response and provide which regulations provide for such a compliance option.

Objection:
AES Indiana objects to the Request on the grounds and to the extent it mischaracterizes the Company's assertions regarding the use of a carbon tax to comply with existing regulations, including the final GHG rules that were recently published by the EPA. Subject to and without waiver of the foregoing objections, AES Indiana provides the following response.

Response:
AES Indiana admits with the following explanation. The final Emissions Guidelines for Greenhouse Gas Emissions for Electric Utility Generating Units do not involve a carbon tax and AES Indiana is not otherwise subject to a carbon tax program.

A carbon tax (price) is not a compliance option under any Federal EPA air regulations for powerplants today. Accordingly, AES Indiana removed the carbon price from the 2024 IRP Update and included specific measures to comply with the EPA's GHG NSPS rules in the updated analysis following the publication of the EPA's GHG NSPS rules. This updated analysis is detailed in REI DR 2-2.

Data Request REI DR 2 - 26

Please admit that there are no active trading platforms for carbon offsets that would allow the Company to comply with the final GHG rules through offsets. If your response is anything other than an unqualified admission, please identify such platforms.

Objection:

Response:
AES Indiana admits with the following explanation. The final Emissions Guidelines for Greenhouse Gas Emissions for Electric Utility Generating Units ("Rule") do not identify carbon trading platforms for existing natural gas-fired steam generating units as a form of standard of performance.[23] The Rule at 40 CFR 60.5775b(a)(2) and 40 CFR 60.5775b(e) provides that States may include standards of performance in alternate forms that include trading programs for affected EGUs in the long-term coal-fired steam generating unit subcategory or the medium-term coal-fired steam generating unit subcategory.

[23] 40 CFR 5775b(c)(6), (7), and (8)

Data Request REI DR 2 - 27

What is the Company's assumption as to the Social Cost of Carbon in its analyses?

Objection:

Response:

Please see pg. 132 of AES Indiana' 2022 IRP for details regarding the Company's use of a fraction of the Social Cost of Carbon as a basis for the carbon price of $6.49 per MWh included in the Company's 2022 IRP and 2024 IRP Update. This carbon price was removed from the analysis in light of the recently promulgated EPA GHG rules. See the Company's response to REI DR 2-2 for details regarding this updated analysis.

Data Request OUCC DR 3 - 1

On page 13, lines 9-12 of AES Witness Collier's direct testimony, she states that Petersburg 3 and 4 would be subject to the proposed Greenhouse Gas New Source Performance Standards under CAA Section 111(d). How would AES Indiana comply with the proposed standards, and how would compliance impact the projected life of the plant?

Objection: AES Indiana objects to the Request on the grounds and to the extent it is vague and ambiguous. Subject to and without waiver of the foregoing objections, AES Indiana provides the following response.

Response:
Witness Collier's direct testimony, page 13, lines 9-14 states:

> Upon repowering to natural gas, Petersburg Units 3 and 4 would be existing natural gas-fired EGUs under the proposed rule. As such, based on the proposed rule, the repowered Units 3 and 4 would be subject to an emissions limit based on routine methods of operation and maintenance.
>
> The requirements of a final CAA Section 111(d) rule, and the results of any associated legal challenges, remain uncertain. EPA may issue a final rule in early 2024.

The 2023 proposed Greenhouse Gas New Source Performance Standards under CAA Section 111(d) discussed in direct testimony identified in the Request (Collier, page 13, lines 9-12) would require states to develop State Plans establishing standards of performance for electric generating units based on EPA's emissions guidelines. Under the 2023 proposal, this would include Petersburg Units 3 and 4 as existing natural gas-fired EGUs. As such, specific requirements for Petersburg Units 3 and 4 would be established through the state rulemaking process with a State Plan due within 24 months of a final EPA Section 111(d) rule and with a possible compliance deadline of January 1, 2030. Although a proposed State Plan has not yet been developed, EPA's proposed 2023 emissions guidelines for existing natural-gas fired EGUs is based on routine methods of operation and maintenance, which would occur through normal operational processes and would not be expected to impact the projected life of the plant.

On April 25, 2024, EPA released a pre-publication version of its final rules regulating greenhouse gas emissions from electric generating units under Section 111 of the Clean Air Act. The regulation being finalized under Section 111(d) of the Clean Air Act, at 40 CFR 60, Subpart UUUUb, would require states with affected existing coal-fired and existing natural gas-fired steam generating electric generating units (EGUs) (i.e., electric utility boilers) to submit State Plans to EPA for approval. State Plans must include standards of performance (i.e., emissions limitations) for each affected existing unit in the state based on EPA's determined Best System of Emissions Reductions (BSER) for the particular type of unit. An existing unit is one that commenced construction on or before January 8, 2014[1]. An EGU is considered to be coal-fired if it combusts, or is capable of combusting, coal on or after January 1, 2030[2]. A unit is considered to be natural gas-fired if it combusts natural gas, and no longer retains the capability to fire coal, on and after January 1, 2030[3]. EPA is establishing presumptively approvable standards of performance for states to use in establishing emissions limitations in their State Plans. However, states may apply less stringent, in some circumstances[4], or more stringent emissions limitations than the presumptively approvable standards.

For existing coal-fired affected EGUs, EPA is finalizing Emissions Guidelines based on the timeframe for expected continued coal combustion. Coal-fired affected EGUs that commit to cease coal combustion prior to January 1, 2032, are not subject to emissions limitations. Coal-fired affected EGUs that plan to cease coal combustion after January 1, 2032 and before January 1, 2039 are subject to Emissions Guidelines based on 40% natural gas co-firing with a presumptively approvable standard of 16% reduction in emissions rate compared to a unit-specific baseline with compliance required starting for calendar year 2030. Coal-fired affected EGUs that plan to operate after January 1, 2039 are subject to Emissions Guidelines based on 90% carbon capture and sequestration with a presumptively approvable standard of 88.4% reduction in emissions rate compared to a unit-specific baseline with compliance required starting for calendar year 2032.

For existing natural gas-fired affected EGUs, EPA is finalizing Emissions Guidelines based on load type with compliance required starting for calendar year 2030. Low load

[1] 40 CFR 60.5845b(a)(1)
[2] 40 CFR 60.5880b: "*Coal-fired steam generating unit* means an electric utility steam generating unit or IGCC unit that meets the definition of "fossil fuel-fired" and that burns coal for more than 10.0 percent of the average annual heat input during any continuous 3-calendar-year period after December 31, 2029, or that retains the capability to fire coal after December 31, 2029."
[3] 40 CFR 60.5880b: "*Natural gas-fired steam generating unit* means an electric utility steam generating unit meeting the definition of "fossil fuel-fired," that is not a coal-fired or oil-fired steam generating unit, that no longer retains the capability to fire coal after December 31, 2029, and that burns natural gas for more than 10.0 percent of the average annual heat input during any continuous 3-calendar-year period after December 31, 2029, or for more than 15.0 percent of the annual heat input during any calendar year after December 31, 2029."
[4] Based on remaining useful life and other factors as described in 40 CFR 60.5775b(j).

affected EGUs[5] are subject to Emissions Guidelines based on use of uniform fuels with a presumptively approvable emissions limit of 130 pounds CO_2 per million Btu (lb CO_2/MMBtu). Intermediate load EGUs[6] are subject to Emissions Guidelines based on routine methods of operation and maintenance with a presumptively approvable emissions limit of 1,600 pounds per megawatt hour (gross) (lb/MWh-gross). Base load EGUs[7] are also subject to Emissions Guidelines based on routine methods of operation and maintenance, but with a presumptively approvable emissions limit of 1,400 lb/MWh-gross.

If AES Indiana were to continue to operate Units 3 and 4 as coal-fired after January 1, 2032, emissions reductions of 16% as compared to baseline emissions could be required, consistent with application of 40% natural gas co-firing, resulting in capital investment. If Units 3 and 4 continued to operate as coal-fired after January 1, 2039, emissions reductions of 88.4% compared to baseline emissions could be required, consistent with application of carbon capture sequestration, likely resulting in significant capital investment.

By repowering Units 3 and 4 and eliminating their capability to combust coal, the Units will be considered natural gas-fired EGUs under the final greenhouse gas regulations and subject to emissions limits based on routine methods of operation and maintenance, as established in a State Plan.[8] As such, it is not expected that additional capital investment or operational expenses would be required beyond routine methods of operation and maintenance.

[5] Low load EGUs are those with a capacity factor less than 8%.
[6] Intermediate load EGUs are those with a capacity factor of 8 to 45%.
[7] Base load EGUs are those with a capacity factor greater than or equal to 45%.
[8] If a state does not develop an approvable State Plan, EPA is required to develop a Federal Plan for that state.