Commissioner	Yes	No	Not Participating
Huston	√		
Bennett	√		
Freeman	√		
Veleta	√		
Ziegner	√		

ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF INDIANAPOLIS POWER & LIGHT COMPANY D/B/A AES INDIANA ("AES INDIANA") FOR (1) ISSUANCE OF CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO REPOWER PETERSBURG GENERATING UNITS 3 & 4 TO OPERATE ON NATURAL GAS ("PETERSBURG REPOWERING PROJECT"); (2) APPROVAL OF PETERSBURG REPOWERING PROJECT AS A CLEAN ENERGY PROJECT; AND (3) ASSOCIATED ACCOUNTING AND RATEMAKING, INCLUDING RECOVERY OF PROJECT COSTS, PROJECT DEVELOPMENT COSTS, FGD DEWATERING AND RELATED COSTS, THE REMAINING NET BOOK VALUE OF PETERSBURG UNITS 3 AND 4 RETIRED ASSETS, AND CERTAIN MATERIALS AND SUPPLIES INVENTORY.	**CAUSE NO. 46022** **APPROVED: NOV 06 2024**

<u>ORDER OF THE COMMISSION</u>

Presiding Officers:
James F. Huston, Chairman
Jennifer L. Schuster, Senior Administrative Law Judge

On March 11, 2024, Indianapolis Power & Light Company d/b/a AES Indiana ("AES Indiana" or "Petitioner") filed its Verified Petition for issuance by the Indiana Utility Regulatory Commission ("Commission") of a certificate of public convenience and necessity ("CPCN") to repower Petersburg Generating Units 3 and 4 to operate on natural gas ("Project" or "Petersburg Repowering Project"), for approval of the Project as a clean energy project and for associated accounting and ratemaking relief as further described below. On March 11, 2024, Petitioner also filed the testimony and attachments of the following witnesses:

- John Bigalbal, Chief Operating Officer Generation, U.S. Utilities, AES U.S. Services;
- G. Aaron Cooper, Chief Commercial Officer, U.S. Utilities, AES U.S. Services;
- Angelique Collier, Director, Global Environmental Affairs, AES U.S. Services;
- Erik K. Miller, Director, Resource Planning, AES Indiana;
- Chad A. Rogers, Director, Regulatory Affairs, AES Indiana; and

- Karin Mehringer, Controller, AES U.S. Services.[1]

AES Indiana submitted its workpapers on March 12, 2024.

On March 28, 2024, Reliable Energy, Inc. ("REI") filed a petition to intervene, which was granted on April 10, 2024.

On June 4, 2024, REI filed a motion for summary judgment, or in the alternative, motion to stay proceedings ("REI Motion"). AES Indiana filed its response in opposition to the REI Motion on June 14, 2024, and REI filed its reply on June 21, 2024.

On June 5, 2024, the Indiana Office of Utility Consumer Counselor ("OUCC") filed the testimony and attachments of the following witnesses:

- Brian R. Latham, Utility Analyst in the OUCC's Electric Division; and
- Roopali Sanka, Utility Analyst in the OUCC's Electric Division.

On June 5, 2024, REI filed the testimony and attachments of the following witnesses:

- Michael J. Nasi, Partner at Jackson Walker LLP; and
- Emily S. Medine, Principal, Energy Venture Analysis, Inc.

On June 26, 2024, AES Indiana filed the rebuttal testimony, attachments, and workpapers of witnesses Bigalbal, Cooper, Collier, Miller, and Rogers.[2]

On July 16, 2024, REI filed a Motion for Leave to Submit Supplemental Authority. By docket entry dated July 18, 2024, this Motion, as well as the earlier REI Motion, were both denied.

The Commission conducted an evidentiary hearing in this Cause at 9:30 a.m. on August 6, 2024 in Room 222 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. Petitioner, the OUCC, and REI participated in the evidentiary hearing by counsel, and the prefiled evidence and testimony of Petitioner, the OUCC, and REI were admitted into the record without objection.

Based upon applicable law and evidence of record, the Commission now finds:

1. <u>Notice and Jurisdiction</u>. Notice of the hearing in this Cause was given and published by the Commission as required as required by law. AES Indiana is a "public utility" within the meaning of that term as used in Ind. Code §§ 8-1-2-1 and 8-1-8.5-1. AES Indiana is also an "energy utility" as defined in Ind. Code § 8-1-2.5-2 and an "eligible business" as defined in Ind. Code § 8-1-8.8-6. AES Indiana provides "public utility service" as defined in Ind. Code § 8-1-8.5-1. Accordingly, the Commission has jurisdiction over AES Indiana and the subject matter of this proceeding.

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[1] On July 23, 2024, AES Indiana substituted Karin Mehringer to adopt testimony previously prefiled by Patrick Donlon.

[2] AES Indiana filed revisions to its prefiled testimony on July 15, 18, and 31, 2024.

2. Petitioner's Characteristics and Business. AES Indiana is a public utility corporation organized and existing under Indiana law, with its principal office at One Monument Circle, Indianapolis, Indiana. AES Indiana is engaged in rendering electric utility service in Indiana, and owns and operates, among other properties, plant and equipment within Indiana that are used for the generation, transmission, delivery and furnishing of such service to the public.

3. Relief Requested. AES Indiana requests that the Commission issue a CPCN to repower Petersburg Generating Units 3 and 4 to operate on natural gas (transitioning from their current coal-burning operation) and approve the Petersburg Repowering Project, including the associated Project agreements, as a clean energy project and recovery of those costs as proposed by AES Indiana. AES Indiana also requests approval of associated accounting and ratemaking, including: 1) deferral and subsequent recovery through rates of a return of and on its investment in the Petersburg Repowering Project; 2) accounting for flue gas desulfurization ("FGD") dewatering and related costs; 3) creation of regulatory assets for the remaining net book value of the Petersburg Units 3 and 4 assets that will be retired due to the conversion, amortization of those regulatory assets based upon Commission-approved depreciation rates, and recovery of the regulatory assets through inclusion in AES Indiana's rate base and ongoing amortization in AES Indiana's future rate cases; 4) accounting and ratemaking for materials and supplies inventory that will no longer be used following the conversion; and 5) deferral and subsequent recovery through rates of prudently incurred Project development costs in the event the Petersburg Repowering Project is not approved.

4. Statutory Framework. Ind. Code § 8-1-8.5-5 sets forth the criteria for the Commission to grant a CPCN. Ind. Code § 8-1-8.8-2 concerns the development of "clean energy projects." Ind. Code § 8-1-8.8-2 (by referencing Ind. Code § 8-1-37-4(a)(21)) defines "clean energy project" to include electricity that is generated from natural gas at a facility constructed or repowered in Indiana after July 1, 2011, which displaces electricity generation from an existing coal-fired generation facility. Under Ind. Code § 8-1-8.8-11, the Commission "shall encourage clean energy projects" by authorizing financial incentives, such as the recovery of costs and expenses incurred during construction and operation of the projects, if the projects are found to be just and reasonable. Ind. Code § 8-1-2-0.5 provides that it is the continuing policy of the state 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. Ind. Code § 8-1-2-0.6 provides that it is the 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 following attributes of electric utility service: reliability, affordability, resiliency, stability, and environmental sustainability (the "Five Pillars"). Ind. Code § 8-1-2-10 provides the Commission authority over a utility's accounting; this section also provides that a public utility may defer certain costs as a regulatory asset and recover such deferred costs through rates over a reasonable period. Ind. Code § 8-1-2-14 generally requires a public utility to keep its books, accounts, and records as prescribed or approved by the Commission.

5. Petitioner's Evidence.

A. Proposed Repowering Project. Mr. Bigalbal explained that the Project will repower Petersburg Units 3 and 4 to fire natural gas instead of coal. He said that the Project will be designed to maintain the current steam capacity of each boiler. He testified that the repowering includes constructing a natural gas lateral pipeline, approximately one mile in length, with associated values and metering that will connect to Midwestern Gas Transmission Company's ("MGT") interstate pipeline. Mr. Bigalbal added that a natural gas conditioning and pressure reducing station will connect the lateral to the plant and supply gas at the necessary pressure and condition. He stated that the conversion also includes a change in firing systems by removing the existing coal burners and oil igniters and installing natural gas burners and ignition systems, along with reconfigured burner management systems. He said that the coal delivery piping will be removed as necessary for the installation of new natural gas piping and added that a flue gas recirculation ("FGR") system will be installed to help control steam temperatures and nitrogen oxide emissions on Unit 4.

Mr. Bigalbal explained that, to minimize the cost of the conversion project, Unit 3 will not have FGR, and nitrogen oxides ("NOx") will be controlled with the existing selective catalytic reduction ("SCR") system. He said that surface area will be added to the superheater and reheater circuits to increase heat transfer and help control steam temperatures; the coal handling equipment and byproducts dewatering will be retired in place; the bottom ash handling system under the furnace bottom will be repurposed, as required for the gas conversion, and the remaining bottom ash system for both boilers and submerged flight conveyors will be retired in place. He testified that the FGD and Mercury and Air Toxics Standards ("MATS") systems will be removed from service and retired in place, with portions of each removed to allow access for new ductwork; the electrostatic precipitator on Unit 4 will be removed from service and dismantled, and new ductwork will be installed; the electrostatic precipitator on Unit 3 will be retired in place; new ductwork for the Unit 4 FGR system and for the boilers exhaust will be installed; and the existing chimneys will be used.

Messrs. Cooper and Bigalbal testified regarding natural gas transportation, noting that the engineering and permitting for the natural gas lateral is underway. Natural gas will be supplied via the MGT pipeline, which is an interstate pipeline that runs across the Petersburg Station property. Mr. Cooper testified that the transportation that AES Indiana has contracted will allow for deliveries from Rockies Express Pipeline, Texas Gas Transmission, and Tennessee Gas Pipeline. He stated that AES Indiana already conducts business on many of these pipelines and has multiple suppliers with enough fuel to ensure adequate supply for Petersburg Generating Station.

Mr. Bigalbal testified that AES Indiana and MGT have negotiated a facilities construction agreement. He stated that, under the agreement, MGT will provide the engineering, permitting, material, and construction of the natural gas lateral that will provide gas to the Petersburg plant from MGT's interstate pipeline that runs through the plant's property.

Mr. Cooper testified that AES Indiana has worked with MGT to ensure firm service for a maximum burn day. He discussed the selection criteria for gas transportation and supply services. He said the cost of natural gas acquired to fuel Petersburg Units 3 and 4 would be included in AES Indiana's fuel adjustment clause. Mr. Cooper testified that, following the conversion, the dispatch of the repowered units will be driven by natural gas prices rather than coal prices, and the offer parameters impacted by the conversion will be updated, including reduced startup costs, any changes to heat rate curves, and variable operation and maintenance costs.

Mr. Bigalbal testified that no Federal Energy Regulatory Commission ("FERC") filings or approvals are required for the Project. He and Mr. Cooper testified about the Petersburg Repowering Project's participation in the Midcontinent Independent System Operator ("MISO"). They stated the Project does not need any additional agreements with MISO because Units 3 and 4 already have interconnection agreements, the repowering will use the existing generators, and the repowering will be considered to have a *de minimis* impact to the transmission system. Mr. Cooper stated that no transmission upgrades or related studies, such as those performed for new interconnections, are required. Mr. Cooper said that AES Indiana has and will follow all MISO processes and protocols regarding the Petersburg Repowering Project and will remain in contact with MISO about the process and any capacity accreditation changes related to the repowering.

B. <u>Project Schedule</u>. Mr. Bigalbal stated that the repowering of Petersburg Units 3 and 4 will be staggered to allow one unit to remain available while the other undergoes an outage to complete the repowering. He explained that the plan is to perform the conversion on Unit 3 first with Unit 4 following once the startup and commissioning of Unit 3 has been completed. He said Unit 3's repowering outage is expected to start in February 2026 and be completed in May 2026. He added that, once completed, it will take approximately one month for startup, commissioning, and testing to reach a commercial operation date ("COD") in June 2026.

Mr. Bigalbal testified that Unit 4's outage would start in June 2026 and be completed in October 2026. He said that Unit 4 will take an additional month for startup, commissioning, and testing, and should reach a COD in December 2026. He said that the outage schedules and scope of work were optimized to reduce or avoid the cost of capacity purchases during the winter periods. He said the units are expected to be operational approximately two weeks after their outage completion and startup and commissioning has been completed. He stated that final completion of the Project is expected in the first quarter of 2027, two months after Unit 4's outage completion to perform reliability tests, address miscellaneous items, and to complete as-built drawings. He said the units will be operational during the two months leading up to final completion while the reliability tests are being performed.

Mr. Bigalbal identified March 2024 as the deadline for issuance of the limited notice to proceed ("LNTP") for engineering only. He said a notice to proceed ("NTP") will need to be issued by October 1, 2024 in order to ensure that long lead time items can be ordered, manufactured, and received in time to meet the construction start of February 2026. He said engineering, procurement, planning, and scheduling will be ongoing up to the start of Unit 3's outage. He concluded that the total time from LNTP to final completion is expected to be about 35 months.

With respect to current status of the Project's development, Mr. Bigalbal testified that technical specifications have been finalized, and the initial thermal design has been completed. AES Indiana has also executed an engineering, procurement, and construction agreement ("EPC Agreement"). Mr. Bigalbal said that the EPC Agreement establishes well-defined expectations of the performance by the Contractor and added that AES Indiana will utilize a dedicated project management team to complete the Petersburg Repowering Project, which will include a project director and engineering, project controls, construction management, safety, and operations and training personnel. He said that this team will provide site supervision, contract management, and administration, and ensure that safety and technical specifications are in compliance with the EPC Agreement and support timely delivery of the Project.

C. **Best Estimate of Project Costs.** Mr. Bigalbal testified that the best estimate for the cost of the Repowering Project is $293.2 million (excluding allowance for funds used during construction ("AFUDC")), comprised of EPC cost, owner's costs, gas lateral cost, and contingency. He explained how the EPC cost estimate was developed and discussed each of the components of the best estimate.

Mr. Bigalbal testified that AES Indiana does not anticipate a need for additional investment beyond the best estimate, but noted that situations such as force majeure, unforeseeable conditions at the site, and changes in law, excused events, or AES Indiana-initiated change orders, could result in a need for additional investment. He stated that the costs of any such additional investment in excess of the contingency included in the best estimate would be presented by AES Indiana to the Commission for review and approval prior to recovery through rates. Mr. Bigalbal discussed the EPC Agreement provisions that limit the possibility of Project cost increases.

Mr. Bigalbal opined that the estimated Project cost is reasonable, explaining that the Project best estimate is the result of the recent competitive EPC request for proposal ("RFP") process and direct negotiation with the bidders as further discussed below.

D. **Competitive Bidding Process.** Mr. Bigalbal testified that AES Indiana conducted a competitive RFP process for the EPC contract for the Petersburg Repowering Project. He explained that AES Indiana worked with Sargent & Lundy, an engineering consulting firm, on the Petersburg Repowering RFP ("Repowering RFP") development and bid evaluation. He stated that Sargent & Lundy also participated in the technical discussions and negotiations with the Repowering RFP bidders to ensure impartiality.

Mr. Bigalbal testified that the Repowering RFP was issued in March 2023, and three proposals were received. After the bids were received, AES Indiana performed due diligence, including technical reviews and site visits of facilities that underwent similar coal to gas conversions performed by the bidders. He said that technical and commercial contract negotiations were conducted with all three bidders, and the EPC award ultimately went to the bidder with the best negotiated commercial terms and price.

Mr. Bigalbal noted that the competitive RFP process produced a project cost that was greater than the estimate used in AES Indiana's 2022 Integrated Resource Plan ("IRP"), with the cost difference attributable to inflation, the addition of pressure parts, and owner's contingency that were not a part of the original estimate. He stated that the 2024 IRP update, described by Mr. Miller, which reflects the updated best estimate of the Project cost, shows the Project remains the least cost option to provide electric service to customers.

Mr. Bigalbal testified that AES Indiana executed its EPC Agreement with the Babcock & Wilcox Company ("Contractor") for all civil, mechanical, electrical, and commissioning work related to the Project, other than the work related to the natural gas lateral pipeline to be performed by MGT. He testified that the Contractor will design and supply the equipment and material as required for conversion of the units from coal to gas and ensure that all equipment and material conforms with the scope of work and technical specifications.

Mr. Bigalbal explained that the Contractor has demonstrated with previous projects that it is capable of successfully executing and completing this Project. The EPC Agreement provides AES Indiana oversight to mitigate the risk that the Project will not reach commercial operation on time.

E. **Other Costs.** Mr. Bigalbal testified that FGD dewatering and related costs represent the cost necessary to remove FGD water from Petersburg Generating Station and clean residual FGD tanks and stormwater areas following the repowering of Units 3 and 4. AES Indiana witness Collier explained why AES Indiana may not discharge FGD water and why the FGD water must be removed from Petersburg Generating Station. Mr. Bigalbal provided the total confidential estimate to truck and dispose of the FGD water and clean the FGD tanks and storm water areas. He and Ms. Collier testified that AES Indiana would have to complete these activities even if Petersburg Units 3 and 4 were to be retired now or any point in the future because any such additional costs are associated with the retirement of the FGD, not the repowering of Units 3 and 4. Accordingly, Mr. Bigalbal stated these costs are not included in the best estimate or present value revenue requirement ("PVRR") analysis of the Project.

With respect to materials and supplies inventory, Mr. Bigalbal explained that the prudent operation of Petersburg Units 3 and 4 on coal requires AES Indiana to maintain a level of materials and supplies in inventory. He said that some of the materials and supplies that are currently in AES Indiana's inventory will no longer be needed when Petersburg Units 3 and 4 are converted to operate on natural gas. He provided a list of these materials and supplies in AES Indiana Witness JB Workpaper 1. Mr. Bigalbal estimated that AES Indiana will have a $20 million net of salvage balance of existing materials and supplies inventory that will no longer be needed upon the repowering of Petersburg Units 3 and 4. He said that AES Indiana will sell or scrap these materials and supplies to the extent commercially practicable after the Project is completed. Mr. Bigalbal testified that AES Indiana would have an inventory of materials and supplies to maintain this coal-specific equipment and other assets whether Petersburg Units 3 and 4 were to be retired or repowered now or at any point in the future. at 28. Thus, he stated that these costs are not included in the best estimate or PVRR analysis of the Project.

F. **Prudence of Costs Incurred Prior to Receiving Commission Approval.** Mr. Bigalbal also testified about Project costs estimated to be incurred by AES Indiana prior to receipt of a Commission order in this proceeding—specifically, the cost of an initial engineering study to estimate the cost of the conversion to use as an input in the IRP economic modeling, contract engineering and construction services (such as permitting services, technical and performance evaluations, and construction engineering); the internal labor of the dedicated Project team; other owner's costs (including costs related to pre-outage testing, field office expenses, preparation work, independent testing, legal expenses, and safety costs); and the cancellation fee that will be incurred under the EPC Agreement if the Project is not approved. He estimated these costs will total approximately $21 million in October 2024, $26 million in November 2024, and $29 million in December 2024. He said that AES Indiana has worked to minimize these costs through negotiations with the Contractor.

AES Indiana witness Rogers described the accounting and ratemaking treatment AES Indiana requests to recover these prudently incurred costs in the event the Commission does not approve the Petersburg Repowering Project.

G. <u>IRP</u>. As discussed by AES Indiana witnesses Miller and Bigalbal, AES Indiana's 2022 IRP identified a preferred resource portfolio and Short-Term Action Plan, both of which include the conversion of Petersburg Units 3 and 4 to operate using natural gas.

Mr. Miller provided an overview of AES Indiana's 2022 IRP and how it was developed. He stated that the preferred resource portfolio represents AES Indiana's selected long-term supply-side and demand-side resource mix that safely, reliably, efficiently, and cost-effectively meets the electric system demand, while taking cost, risk, and uncertainty into consideration, while its Short-Term Action Plan is the schedule of activities and goals AES Indiana developed to begin efficient implementation of its preferred resource portfolio. Mr. Miller explained that the study period for the 2022 IRP was 2023-2042, and the 2022 IRP was submitted to the Commission in December 2022. He testified that the 2022 IRP development included input from stakeholders through a public advisory process.

Mr. Miller explained that, to select the preferred resource portfolio and Short-Term Action Plan in the IRP analysis, AES Indiana used the Five Pillars codified in Ind. Code § 8-1-2-0.6 to evaluate five discrete strategies (referred to as "Candidate Portfolios") and one optimization for the remaining Petersburg coal units. The Candidate Portfolios included: 1) keeping Petersburg operating on coal for its remaining useful life; 2) converting Petersburg to operate using natural gas in 2025 ("Petersburg Conversion"); 3) retiring Petersburg Unit 3 in 2026 and keeping Petersburg Unit 4 operating on coal for its remaining useful life; 4) retiring both Units 3 and 4 in 2026 and 2028, respectively (this strategy selected a 300 megawatt ("MW") combined cycle gas turbine and energy storage resources as replacement for retiring the Petersburg Units); and 5) retiring Units 3 and 4 in 2026 and 2028, respectively, and replacing them with only wind, solar, and storage resources. Mr. Miller described the modeling performed by AES Indiana to evaluate replacement options for Petersburg and the cost effectiveness of the Candidate Portfolios in the 2022 IRP.

Mr. Miller testified that AES Indiana first conducted a scenario analysis that evaluated how the five strategies would perform in very different potential futures. He stated that converting Petersburg Units 3 and 4 to natural gas performed the best across the scenarios and potential futures. He also stated that the Candidate Portfolio option to convert Petersburg Units 3 and 4 to natural gas performed the best overall for customers in terms of the Five Pillars. After considering these results, AES Indiana selected the Petersburg Conversion portfolio for the preferred resource portfolio and Short-Term Action Plan.

Mr. Miller discussed how the Petersburg Conversion maintains AES Indiana's level of capacity at Petersburg and ensures reliability, stability, and resiliency for customers. He stated the 2022 IRP demonstrates that the Petersburg Conversion is a reasonable least-cost option for customers. The bulk of cost savings from converting the Petersburg Units from coal to natural gas will come from reduced fixed operating and maintenance ("O&M") costs associated with ancillary processes specifically for coal operation such as coal handling and pollution controls.

Mr. Miller testified regarding the updated modeling AES Indiana performed in 2024 to determine if the preferred resource portfolio and Short-Term Action Plan, which include the Petersburg Conversion, remain the least cost strategy and consistent with the results of the 2022 IRP. He described the planning assumption updates included in the 2024 IRP update analysis and discussed the updated resource mix compared to the 2022 IRP. Mr. Miller discussed affordability, compared the annual revenue requirements, and explained how reliability and sustainability were considered in the 2024 IRP update. He said the 2024 IRP update results demonstrate the Candidate Portfolio that converts Petersburg Unit 3 and 4 from coal to natural gas in 2026 still performs the best overall for customers in terms of affordability, sustainability, reliability, resiliency, and stability. Mr. Miller said these savings are estimated to be approximately $683 million over the planning period. He explained that the other Candidate Portfolios are not reasonable alternatives to the portfolio that converts Petersburg Units 3 and 4 from coal to natural gas in 2026. Figure 1 of Mr. Miller's testimony, reproduced below, illustrates the advantages of the Petersburg conversion option over other portfolios considered by Petitioner.

Figure 1: 2022 IRP Scorecard Evaluation Results[8]

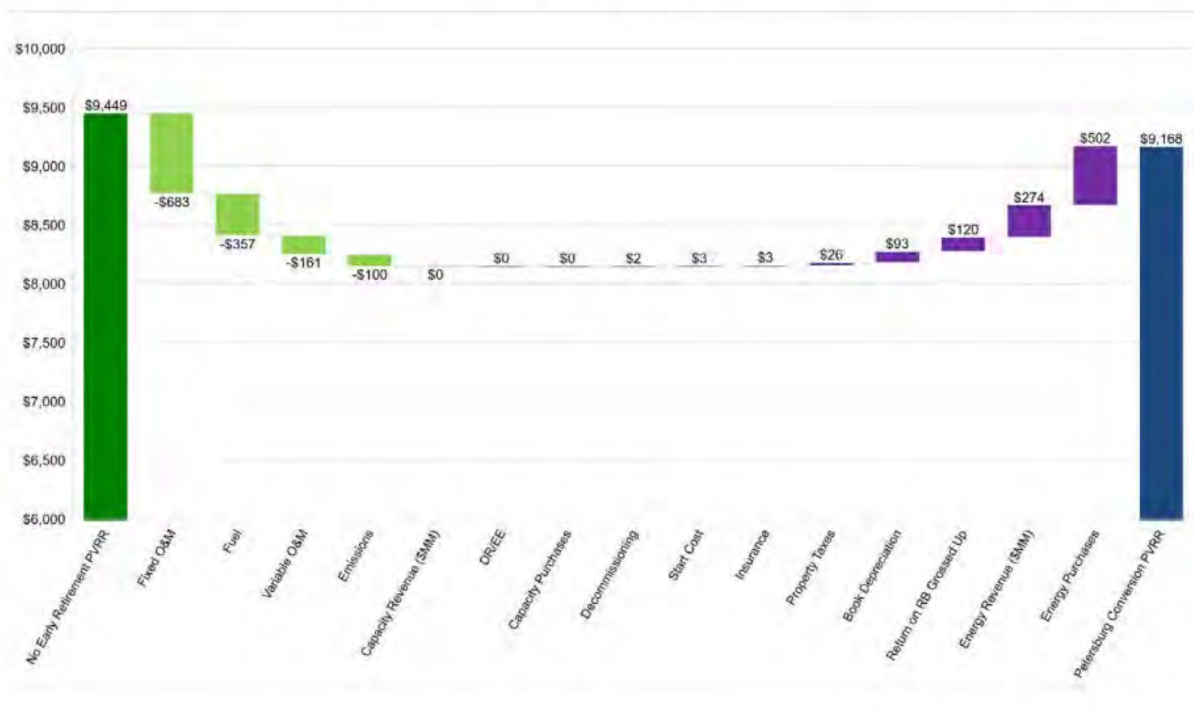
	Affordability	Environmental Sustainability						Reliability, Stability & Resiliency	Risk & Opportunity							Economic Impact	
	20-yr PVRR	*CO_2 Emissions*	*SO_2 Emissions*	*NO_x Emissions*	*Water Use*	*Coal Combustion Products (CCP)*	*Clean Energy Progress*	*Reliability Score*	*Environmental Policy Opportunity*	*Environmental Policy Risk*	*General Cost Opportunity **Stochastic Analysis***	*General Cost Risk **Stochastic Analysis***	*Market Exposure*	*Renewable Capital Cost Opportunity (Low Cost)*	*Renewable Capital Cost Risk (High Cost)*	*Generation Employees (+/-)*	*Property Taxes*
	Present Value of Revenue Requirements ($000,000)	Total portfolio CO2 Emissions (mmtons)	Total portfolio SO2 Emissions (tons)	Total portfolio NOx Emissions (tons)	Water Use (mmgal)	CCP (tons)	% Renewable Energy in 2032	Composite score from Reliability Analysis	Lowest PVRR across policy scenarios ($000,000)	Highest PVRR across policy scenarios ($000,000)	P5 [Mean - P5]	P95 [P95 – Mean]	20-year avg sales + purchases (GWh)	Portfolio PVRR w/ low renewable cost ($000,000)	Portfolio PVRR w/ high renewable cost ($000,000)	Total change in FTEs associated with generation 2023 - 2042	Total amount of property tax paid from AES IN assets ($000,000)
1	$ 9,572	101.9	64,991	45,605	36.7	6,611	45%	7.95	$ 8,860	$ 11,259	$ 9,271 [-$264]	$ 9,840 [$306]	5,291	$ 9,080	$ 10,157	222	$ 154
2	$ 9,330	72.5	13,533	22,146	7.9	1,417	55%	7.95	$ 8,564	$ 11,329	$ 9,030 [-$334]	$ 9,746 [$382]	5,222	$ 8,763	$ 9,999	99	$ 193
3	$ 9,773	88.1	45,544	42,042	26.7	4,813	52%	7.86	$ 9,288	$ 11,462	$ 9,608 [-$294]	$ 10,237 [$336]	5,737	$ 9,244	$ 10,406	195	$ 204
4	$ 9,618	79.5	25,649	24,932	15.0	2,700	48%	7.90	$ 9,135	$ 11,392	$ 9,295 [-$287]	$ 9,903 [$321]	5,512	$ 9,104	$ 10,249	74	$ 242
5	$ 9,711	69.8	25,383	24,881	14.8	2,676	64%	7.57	$ 9,580	$ 11,275	$ 9,447 [-$280]	$ 10,039 [$312]	6,088	$ 9,017	$ 10,442	55	$ 256
6	$ 9,262	76.1	18,622	25,645	10.9	1,970	54%	7.95	$ 8,517	$ 11,226	$ 8,952 [-$304]	$ 9,629 [$352]	5,136	$ 8,730	$ 9,909	88	$ 185

Strategies

- **1.** No Early Retirement
- **2.** Petersburg Conversion to 100% Natural Gas (est. 2025)
- **3.** One Pete Unit Retires in 2026
- **4.** Both Pete Units Retire in 2026 & 2028
- **5.** "Clean Energy Strategy" – Both Pete Units Retire and replaced with Renewables in 2026 & 2028
- **6.** Encompass Optimization without Predefined Strategy – Selects Pete 3 Refuel in 2025 & Pete 4 Refuel in 2027

Mr. Miller testified that the IRP analysis demonstrated that the Preferred Resource Portfolio, which includes the Petersburg Conversion, is the most cost effective for customers out of the strategies considered (see Affordability metric in Figure 1 above). The Preferred Resource Portfolio has a lower PVRR by approximately $240 million over the 20-year IRP planning period compared to the economically next best option or keeping Petersburg as coal-fired. Mr. Miller testified that the largest savings to PVRR are from a $657 million reduction in fixed O&M costs primarily associated with ancillary processes specifically for coal operation, e.g., coal handling and coal pollution controls. He stated that the Preferred Resource Portfolio also results in a $113 million reduction in emissions costs and $93 million reduction in variable O&M costs over the period. The PVRR of the Petersburg conversion, estimated after the 2024 IRP Update, is illustrated by Figure 9 in Mr. Miller's testimony, reproduced below.

Figure 9. PVRR of the Petersburg Conversion Compared to PVRR of Continuing to Operate Petersburg on Coal – 2024 IRP Update



H. **<u>Consideration of Resource Alternatives (Ind. Code § 8-1-8.5-4)</u>.** Mr. Miller discussed AES Indiana's consideration of other resource options. He explained that the purchase of power via the spot energy market was considered, but noted that at approximately 1,000 MW, the Petersburg Units 3 and 4 are needed as a capacity resource. He added that relying on the spot market would put AES Indiana in a long-term position of relying on market transactions for large amounts of capacity, putting AES Indiana customers at risk for price volatility and reliability issues.

Mr. Miller also discussed the "interchange of power" and "pooling of facilities" as these phrases are used in Ind. Code § 8-1-8.5-4, and explained that these statutory references predate the development of, and AES Indiana's membership in, MISO. He said the current MISO market is effective at fully utilizing existing capacity resources in the region, but does not eliminate the need for new capacity resources to address potential load growth and retirements of older, less efficient coal-fired units in the region. Mr. Miller then discussed the consideration of wind and solar resources as alternatives and said the 2024 IRP update analysis demonstrates that this alternative path is more expensive and less reliable for AES Indiana customers compared to the Petersburg Conversion strategy. Mr. Miller also discussed energy efficiency and demand response as alternatives to the Project and explained that these demand-side resources were evaluated on a consistent and comparable basis with supply-side resources. The target levels of demand-side management ("DSM") savings in AES Indiana's approved 2024 DSM plan as well as its anticipated 2025-2026 DSM plan are consistent with the IRP's Short-Term Action Plan. He noted that energy efficiency and demand response are not sufficient to fill the need for generation under the new seasonal resource adequacy construct, particularly in the winter season.

I. State Utility Forecasting Group ("SUFG"), Indiana Electricity Projects and MISO Reliability Imperative Report. Mr. Miller testified that AES Indiana considered the SUFG's most recent Indiana Electricity Projections report from 2023. He explained that, in the report, the SUFG projected that Indiana will need additional resources in the first half of the forecast, with this need driven by units that will be retiring in that time, and resource additions in the second half of the forecast, with this need driven by both retirements of existing units and increasing demand. He noted that converting Petersburg Units 3 and 4 to natural gas will provide a near one-for-one capacity replacement at Petersburg. As such, he concluded, the Petersburg Conversion will not create a need for additional resources.

Mr. Miller explained that the Petersburg Repowering Project addresses the challenges identified by MISO in its 2024 reliability imperative report in several ways. First, the Petersburg Repowering Project maintains the capacity of the existing Petersburg Units 3 and 4, which will ensure that Petersburg Units 3 and 4 will maintain the vital reliability, resiliency, and stability attributes they currently provide upon completion of the Petersburg Repowering Project. The Petersburg Repowering Project also allows AES Indiana to significantly reduce most air emissions and avoid the significant risks associated with operating a coal-fired resource in the future. Finally, AES Indiana has secured enough firm transportation on the MGT pipeline to ensure firm service for a maximum burn day. Mr. Miller added that the Petersburg Repowering Project will allow AES Indiana to cease coal-fired operation at Petersburg Generating Station, removing all the fuel supply risks MISO identified that are unique to coal-fired generators.

J. Public Convenience and Necessity. Mr. Bigalbal testified that the Project represents the reasonable least cost option from the updated PVRR analysis as discussed by AES Indiana witness Miller. Mr. Bigalbal said the Project results in significant environmental benefits relative to the current use of coal as discussed by AES Indiana witnesses Collier and Miller. Mr. Bigalbal opined that the Project supports reliability, resiliency, and stability by utilizing an existing dispatchable energy resource. He added that the Project avoids $929 million, in present value, of reliability upgrades identified in Quanta's Reliability Analysis that would be necessary over the 20-year period if Petersburg Units 3 and 4 are replaced with inverter-based resources. He also stated that the Petersburg Conversion saves $281 million over the 20-year period, in present value, compared to keeping the units on coal.

He testified that the Project is consistent with AES Indiana's 2022 IRP Short-Term Action Plan as updated in this Cause by Mr. Miller. Mr. Bigalbal added that continuing to operate Petersburg Units 3 and 4 in Pike County will benefit AES Indiana's customers, the local community, and the state, as maintaining facilities in Indiana supports Indiana jobs and provides local taxes to support local communities. Mr. Bigalbal opined that the Project is reasonable and necessary, and the public interest and convenience will be served by Commission approval of the Project and associated relief as proposed by AES Indiana.

K. <u>Clean Energy Project</u>. Mr. Bigalbal testified that AES Indiana is eligible for relief under Ind. Code ch. 8-1-8.8 and that the Project is a "clean energy project" as that term is defined in Ind. Code ch. 8-1-8.8 because the Repowering Project displaces electricity generation from an existing coal-fired generation facility.

L. <u>Accounting and Ratemaking</u>. Mr. Rogers stated that AES Indiana is proposing the following with respect to accounting and ratemaking: 1) approval of and cost recovery for the Project costs and associated agreements; 2) authority to defer depreciation expense, post in-service carrying charges ("PISCC"), and incremental property taxes associated with the Project to a regulatory asset to be recovered in a future base rate case; 3) Commission approval of the decommissioning cost accounting for FGD dewatering and related costs (which are confidential) associated with the Repowering Project; 4) authority to defer for subsequent recovery through rates net material and supplies inventory that will no longer be used as a result of the Repowering Project; 5) authority to defer the Project development costs AES Indiana incurs prior to the issuance of a final Commission Order in this Cause if the Commission does not approve AES Indiana's proposed Repowering Project; and 6) authority to use regulatory asset accounting for the net book value of the retired assets associated with the repowering of Petersburg Units 3 and 4 associated with coal operations.

With respect to the request to defer for subsequent recovery depreciation expense associated with the Project, Mr. Rogers testified that AES Indiana proposes to depreciate the new investment with carrying charges in a regulatory asset for recovery in a future basic rate case using the depreciation rates set forth in the Settlement Agreement in AES Indiana's most recent basic rate case (Cause No. 45911). He stated that a three-year amortization period was used in the analysis included in confidential workpapers in this Cause; however, AES Indiana proposes to address the amortization period for the recovery of the regulatory asset in a future basic rate case.

With regard to AES Indiana's request regarding PISCC on its investment in the Project, Mr. Rogers testified that AES Indiana will record AFUDC on its investments in the Project during the construction period in accordance with the FERC Uniform System of Accounts ("USOA"). He said that, once construction is completed, AES Indiana proposes to defer PISCC on the Project until the Project is reflected in base rates in a future rate case. He said AES Indiana proposes to use the lower of AES Indiana's weighted average cost of capital ("WACC") or AFUDC rate in the calculation of PISCC.

Mr. Rogers explained that, due to the additional equipment installed as part of the Conversion Project, AES Indiana will experience increased incremental property tax expense which is not included in basic rates and charges in Cause No. 45911. Mr. Rogers testified that AES Indiana proposes to defer this incremental property tax expense with carrying charges in a regulatory asset for recovery in a future basic rate case. He said a three-year amortization period was used in the analysis included in confidential workpapers; however, Mr. Rogers stated that AES Indiana proposes to address the amortization period for the recovery of the regulatory asset in a future basic rate case.

Mr. Rogers opined that the proposed accounting and ratemaking treatment for depreciation expense, incremental property taxes, and PISCC is reasonable and consistent with the cost recovery afforded to clean energy projects under Ind. Code § 8-1-8.8-11. He testified that AES

Indiana proposes to defer recovery of the Petersburg Repowering Project costs to a future rate case rather than implement cost recovery via AES Indiana's environmental cost recovery ("ECR") tracker mechanism because the Project's in-service dates (June and December 2026, respectively, for Units 3 and 4) align well with AES Indiana's expected filing of its next basic rate case, using the assumption that rates reflecting the repowering of Petersburg Units 3 and 4 will be placed into effect in 2027. He stated that, if AES Indiana were instead to recover the costs associated with the Petersburg Repowering Project through the ECR tracker mechanism, the first filing that the Project would be eligible for recovery would be ECR 40, with rates effective in March 2027, which would be similar in time and customer rate impact to the rate case approach. He opined that AES Indiana's proposed accounting provides AES Indiana a reasonable opportunity to earn a return on its investment and to recover the investment through rates over time. He also argued that this treatment is consistent with the statutory directive that financial incentives be authorized for approved projects.

Mr. Rogers also explained why AES Indiana's best estimate for the Project does not include costs associated with removing or demolishing existing equipment and facilities at Petersburg Generating Station, testifying that AES Indiana seeks approval to use decommissioning accounting treatment for the FGD dewatering and related costs, which will allow AES Indiana to recover future decommissioning costs through recovery of depreciation expense over the life of the assets. He opined that this proposed accounting for the FGD dewatering and related costs is reasonable because these costs are necessarily incurred for the conversion Project. He stated that these costs are not otherwise reflected in AES Indiana's basic rates.

Mr. Rogers also addressed AES Indiana's proposed accounting and ratemaking treatment for materials and supply inventory that will no longer be necessary due to the repowering of Petersburg Units 3 and 4. He said AES Indiana requests Commission approval to defer this balance to a regulatory asset for recovery in a future basic rate case. He opined that this proposal is reasonable because these materials and supply costs were prudently incurred for use in the provision of retail service in connection with the operation of the Petersburg units on coal. He noted that the Commission has long allowed recovery through the ratemaking process of the costs associated with investments that were once "used and useful," and amortization of costs associated with retired facilities encourages a utility to improve the efficiency of its system by removing obsolete or inefficient property from service. He stated that, while this concept is often considered in the context of the cost of prematurely retired electric plant in service, the principle is the same for inventory. He testified that the materials and supplies inventory costs AES Indiana proposes to defer are not reflected in AES Indiana's basic rates. He stated that when materials and supplies inventory is included as a component of rate base in a general rate case, that treatment provides the utility the return "on" the investment, but not the return "of" the investment. He said that AES Indiana's proposed accounting and ratemaking for this inventory here will provide the return "of" this investment and avoid penalizing AES Indiana for making the economic decision to convert Units 3 and 4.

With regard to project development costs, Mr. Rogers stated that AES Indiana estimates to incur approximately $21.3 million of costs (approximately $22 million including AFUDC) prior to an expected entry of a Commission order in this Cause. He testified that, in the event the Commission does not approve the repowering of Petersburg Units 3 and 4, AES Indiana requests the Commission authorize the deferral of the project development costs and accrual of carrying charges in a regulatory asset for future recovery via amortization in a future basic rate case. He stated that AES Indiana proposes to use the lower of either its WACC or AFUDC rates in the calculation of carrying charges. He opined that these costs are being incurred prudently to preserve the option to repower these units and develop the Project to a point where it may be reviewed by the Commission and implemented in a timely manner. Mr. Rogers stated that the annual revenue requirement impact of this deferral includes the return on the regulatory asset and recovery of the amortization over three years, and the estimated revenue requirement impact equates to approximately $0.73 per month for a residential customer using 1,000 kilowatt-hours ("kWh") each month, which is an increase over current base rates of approximately 0.5%.

Mr. Rogers testified that, if AES Indiana's proposed Project is approved by the Commission, AES Indiana will capitalize the project development costs and capital costs to the construction work in progress account during construction, which will be transferred to utility plant in service upon completion of the Project.

Mr. Rogers testified that the resulting net impact of the requested ratemaking treatment for the Project is estimated to result in a revenue requirement impact of approximately $4.6 million in the first year, equating to an increase in rates of approximately $0.37 per month for a residential customer using 1,000 kWh each month, which is an increase over base rates approved in Cause No. 45911 of approximately 0.3%.

Ms. Mehringer testified that AES Indiana requests the Commission authorize AES Indiana's use of a regulatory asset account for the net book value of Petersburg Unit 3 and 4 coal operations that will be retired upon repowering (the "Retired Assets") associated with the repowering of Petersburg Units 3 and 4. She said that this will allow the regulatory assets to continue to reduce and will also provide assurance of recovery of such remaining net plant balance through AES Indiana's retail rates. She testified that AES Indiana does not seek a change in its retail rates for service in this case, but proposes to amortize the regulatory assets, which reflect the expected net utility plant in service balance for the Retired Assets based on the Commission-approved depreciation rates in effect at the time of retirement. She said this proposal will reduce the regulatory asset as AES Indiana continues to collect amounts reflected for these units through existing retail rates for electric service.

Ms. Mehringer testified that, upon retirement, the Retired Assets will not be fully depreciated, and the requested treatment will prevent a resulting increase to earnings when depreciation expense is ceased upon retirement. She noted that, as compared to stopping depreciation upon retirement, the proposed continued amortization will lessen the amount to be included in rate base in a future rate case, resulting in a lower revenue requirement for future basic rates. She stated that AES Indiana's requested relief recognizes that the Retired Assets have been devoted to and used and useful in the provision of service to AES Indiana's retail customers for decades. Ms. Mehringer also stated that, if the proposed accounting and ratemaking were not used, AES Indiana would experience a significant adverse impact on earnings once each unit is retired.

M. <u>Five Pillars</u>. AES Indiana witnesses Bigalbal and Miller testified that AES Indiana considered the Five Pillars in the development of the 2022 IRP, in the development of the Petersburg Repowering Project, and in the 2024 IRP update.

i. Reliability, Resiliency and Stability. Mr. Bigalbal testified that Petersburg Units 3 and 4 have been in service since 1977 and 1986, respectively, and the units have proven to be reliable and resilient to the ambient conditions and customer needs. He said large rotating steam turbine-generators provide frequency and voltage support to the grid, which in turn provides stability as load conditions change and disturbances occur. He said the conversion of Units 3 and 4 will maintain these attributes into the future.

Mr. Bigalbal testified that converting Petersburg Units 3 and 4 to natural gas supports the ability of the system to reliably supply the firm capacity and energy requirements of customers. He said the ability to use the existing infrastructure at the Petersburg Generating Station, including using MGT's pipeline, which runs across the Generating Station's property, reduces the cost and risk of development and construction of a new facility and accessing an interstate natural gas pipeline that is not onsite.

Mr. Bigalbal testified that the conversion of Units 3 and 4 can be performed in a relatively short period of time and at relatively low cost. He and Mr. Miller opined that the natural gas conversion provides excellent support for intermittent renewable resources because the Units provide the firm capacity that is required for a reliable and stable grid.

Mr. Miller testified that the conversion of Petersburg Units 3 and 4 will result in a near one-for-one capacity change with the units going from a total installed capacity ("ICAP") of 1,040 MW on coal to 1,052 MW on natural gas. He said that the units are forecasted to continue to provide firm dispatchable capacity near or above 90% accreditation in all four seasons of MISO's Seasonal Resource Adequacy Construct when operating on natural gas. He added that, in AES Indiana's 2022 IRP, AES Indiana hired Quanta to perform a Reliability Analysis of the Petersburg Candidate Portfolios and said the Reliability Analysis scores demonstrated that the preferred resource portfolio, which converts Petersburg Units 3 and 4 to natural gas, is as reliable as continuing to fuel those units with coal, and more reliable than retiring those units and replacing them with other resources like wind, solar, and storage.

ii. Affordability. Mr. Bigalbal described the process by which AES Indiana confirmed the affordability of the Project. He said the IRP modeling process and the competitive bidding process are designed to identify the reasonable least cost solution for customers and are consistent with the affordability pillar. He said AES Indiana has taken steps to safeguard costs in the negotiation of the EPC Agreement.

Mr. Bigalbal and Mr. Miller testified that the Preferred Portfolio (which includes the conversion of Petersburg Units 3 and 4 to natural gas) has the lowest PVRR of all the Candidate Portfolios compared to keeping the units on coal. Mr. Bigalbal said the updated PVRR analysis (which used updated commodity prices and Project costs) demonstrates the Project is estimated to save customers $281 million over the 20-year planning period versus the alternatives. Mr. Bigalbal added that neither the 2022 IRP nor the updated analysis includes the additional cost of reliability upgrades that would be necessary to maintain system reliability, stability, and resilience if Petersburg Units 3 and 4 were replaced with 100% inverter-based resources. Mr. Bigalbal said that the estimated cost differential between repowering Petersburg Units 3 and 4 and replacing Petersburg Units 3 and 4 with 100% inverter-based resources is approximately $929 million. Mr. Miller testified that, if these costs were included in the PVRR analysis, it would make the

Petersburg Conversion Strategy more cost effective compared to replacing these units with inverter-based resources.

Witnesses Rogers, Mehringer, and Bigalbal opined that AES Indiana's accounting and ratemaking proposals are also reasonably designed to address affordability of service. Mr. Rogers explained that in the context of resource planning, the way in which affordability and customer rate impact are considered is through the economic analysis of projects as compared to alternatives. He said that the objective of AES Indiana's IRP was to identify a preferred resource portfolio that provides safe, reliable, sustainable, and reasonable least cost electricity service to AES Indiana customers, giving due consideration to potential risks and stakeholder input. He said this policy supports resource planning and the use of ratemaking constructs to mitigate bill impact. Mr. Rogers said the PVRR analysis and rate impact calculation demonstrate that the proposed accounting and ratemaking reasonably considers affordability. He stated that the ratemaking proposed by AES Indiana results in retail electric utility service that is competitive across residential, commercial, and industrial customer classes and this approach is consistent with the affordability pillar.

iii. __Sustainability__. Mr. Bigalbal testified that natural gas has very low sulfur, particulate, and nitrogen levels, making it a low-emission fuel relative to coal. He and AES Indiana witness Collier testified that the Project will significantly reduce the emission rates of sulfur dioxide ("SO_2"), NO_x, particulate matter, and mercury. Mr. Bigalbal stated the Project will also reduce carbon dioxide emission rates by approximately 43% and the Project will eliminate all production of residuals of combustion that coal has. He added that, by eliminating the need for FGD, water use will be significantly reduced. Mr. Miller testified that the preferred resource portfolio, which includes the Petersburg Conversion, performed the best in terms of sustainability in most categories compared to the other Petersburg strategies evaluated in the 2022 IRP.

Ms. Collier testified that AES Indiana needed to obtain a modified Title V Air Permit ("Air Permit") from the Indiana Department of Environmental Management ("IDEM") for the Repowering Project and may need to obtain other state and federal environmental permits. She stated that the Air Permit (both construction and operating) was obtained in 2023 and incorporates applicable air regulations and requirements, as well as the requirements of the 2021 IDEM consent decree applicable to the Petersburg Station.

Ms. Collier testified that substantial reductions in most air emissions will result from repowering the existing coal-fired units with natural gas. She also noted that the repowering of Units 3 and 4 will eliminate future production of coal combustion residuals.

Ms. Collier testified there are a number of additional environmental rules, both proposed and final, that have the potential to affect these units, including, but not limited to, the National Ambient Air Quality Standards ("NAAQS"), Cross State Air Pollution Rule ("CSAPR" or "Good Neighbor Rule"), Cooling Water Intake Structures Rule, Effluent Limitations Guidelines ("ELG") Rule, Water Quality Standards ("WQS"), Coal Combustion Residuals ("CCR") rule, and Greenhouse Gas ("GHG") New Source Performance Standards ("NSPS").

Ms. Collier testified that Pike County is currently designated as attainment for all NAAQS. With respect to CSAPR, she explained that the repowering of Units 3 and 4 will significantly reduce air emissions regulated by CSAPR, namely SO_2 and NO_x. She stated that, while certain emission allocations for future years are uncertain, reductions in emissions of SO_2 and NO_x will facilitate AES Indiana Petersburg's ability to continue to comply with CSAPR. Figures 3 and 11 of Mr. Miller's testimony, reproduced below, illustrates the predicted environmental sustainability benefits, including significant SO_2 and NO_x reductions, of the Petersburg conversion as compared to other options (including continuing to burn coal, "No Early Retirement"), over the planning period.

Figure 3. AES Indiana 2022 IRP Environmental Sustainability Results

		Environmental Sustainability					
		CO_2 Emissions	*SO_2 Emissions*	*NO_x Emissions*	*Water Use*	*Coal Combustion Products (CCP)*	*Clean Energy Progress*
		Total portfolio CO2 Emissions (mmtons)	Total portfolio SO2 Emissions (tons)	Total portfolio NOx Emissions (tons)	Water Use (mmgal)	CCP (tons)	% Renewable Energy in 2032
No Early Retirement	1	101.9	64,991	45,605	36.7	6,611	45%
Petersburg Conversion to 100% Gas (2025)	2	72.5	13,513	22,146	7.9	1,417	55%
One Pete Unit Retires (2026)	3	88.1	45,544	42,042	26.7	4,813	52%
Both Pete Units Retire (2026 & 2028)	4	79.5	25,649	24,932	15.0	2,700	48%
Both Pete Units Retire and Replaced with Wind, Solar & Storage (2026 & 2028)	5	69.8	25,383	24,881	14.8	2,676	64%

Figure 11 – Updated Production Cost Analysis Environmental Sustainability Results

	CO2	SO2	NOx	Water Use	Coal Ash
	Total portfolio CO2 Emissions (mmtons)	Total portfolio SO2 Emissions (tons)	Total portfolio NOx Emissions (tons)	Water Use (mmgal)	CCP (tons)
No Early Retirement	94.5	54,921	40,137	31.2	5,620
Petersburg Conversion	62.2	14,957	18,165	8.6	1,555
Both Petersburg Units Retire	69.7	27,991	24,868	16.3	2,931
Clean Energy Strategy	69.7	27,991	24,866	16.3	2,931

Ms. Collier also stated that Unit 3 plans to maintain its existing SCR as a voluntary emissions control device. With respect to the Cooling Water Intake Structures Rule, Ms. Collier testified that Petersburg Units 3 and 4 are already equipped with a closed cycle cooling system. She added that a reduction in through screen velocity achieved through a reduction in existing pump capacity may be required, but the repowering of Units 3 and 4 is not expected to affect the ability to comply with the requirements of the Cooling Water Intake Structures Rule as repowering does not impact the amount of cooling water withdrawn.

Ms. Collier testified that, while the repowering of Units 3 and 4 does eliminate future production of coal combustion residuals, it does not affect AES Indiana Petersburg's compliance obligations associated with the existing CCR units (*i.e.*, CCR surface impoundments and CCR landfill) at the Petersburg Generating Station, including those related to groundwater monitoring and corrective action, closure requirements and post-closure care. She explained that the existing Petersburg CCR Units are not currently in service, and AES Indiana removed the ash ponds from service and installed a closed-loop bottom ash handling system to dewater bottom ash which would otherwise be sluiced to the ponds.

With regard to the ELG rules, Ms. Collier testified that Petersburg's natural gas-fired operation will not produce the wastewaters regulated by these rules and as such, the repowering of Units 3 and 4 does not require compliance with these rules. Similarly, with respect to compliance with WQS, Ms. Collier explained that AES Indiana Petersburg has already eliminated fly ash, bottom ash, and FGD wastewaters, prior to repowering and as such, repowering does not affect Petersburg's compliance obligations with applicable WQS requirements.

Ms. Collier described the current status and potential impact of GHG regulations potentially affecting Petersburg Generating Station. She discussed the Environmental Protection Agency's ("EPA") 2023 proposed GHG NSPS and stated that, upon repowering to natural gas, Petersburg Units 3 and 4 would be existing natural gas-fired electric generating units ("EGUs") under the proposed rule. She added that, 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. She noted that the requirements of a final rule, as well as any legal challenges to such rule, remain uncertain, and said the EPA is expected to issue a final rule in early 2024.

N. **Other Benefits.** Mr. Bigalbal and Mr. Miller opined that the Project will have a positive social and economic impact to the community of Petersburg and Pike County. Mr. Bigalbal said that the Petersburg facility is the largest taxpayer in the community and provides many direct and indirect jobs. He stated that conversion of the facility will maintain a beneficial level of taxes and employment opportunities for the community. As noted in Mr. Bigalbal's testimony, the Petersburg facility is the largest taxpayer in Pike County (in 2023, paying $2,317,965.68 in taxes, over seven times the amount of the second-largest taxpayer, Norfolk Southern Combined Railroad, which paid $303,775.26)[3] and a major employer in the county. *See* Pet Ex. 1 at 16. Mr. Miller added that the Project will continue to take advantage of the existing MISO interconnection at Petersburg. He also said that, compared to the other strategies, the Petersburg Conversion strategy demonstrated the best general performance across the risk and opportunity metrics that AES Indiana evaluated in the 2022 IRP. Mr. Miller also testified that Petersburg Conversion provides excellent support for intermittent renewable resources because they provide firm capacity that is required for a reliable and stable grid.

[3] See Pet. Ex. 1 at 16, n. 9 (Pike County Treasurer website, http://treasurer.pike.in.datapitstop.us/cgi.exe?CALL_PROGRAM=C009TOPTAXPAYERS) (last accessed October 21, 2024).

6. **<u>OUCC's Evidence</u>.** Mr. Latham reviewed the Project and discussed it from a cost perspective, with consideration of the Project's impact on customer affordability and environmental sustainability. He stated that overall, the OUCC does not oppose Petitioner's request as presented in this Cause.

Mr. Latham reviewed AES Indiana's incremental revenue requirement and said he found no errors in Petitioner's calculations. He also discussed AES Indiana's proposed deferrals and said he did not oppose it. He recommended amortizing the deferred depreciation expense, Petitioner's PISCC, incremental property tax expense, and obsolete inventory over the same period as AES Indiana's rate case expense in its next rate case. He said that this will allow any over- or under-recovery to be netted with any rate case expense recovery variance in subsequent rate cases.

Mr. Latham testified that he ran a simple revenue requirement forecast as if Petitioner filed a rate case in the third year of the Project's operations with rates taking effect at the beginning of the Project's fourth year of operation, assuming AES Indiana recovered the deferred amounts over the assumed three-year period. He discussed his analysis and stated that 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.

Mr. Latham testified that the OUCC opposed AES Indiana's proposed treatment of its Project development costs in the event the Commission does not approve the Project. He testified that, if the Commission does not approve AES Indiana's Project, the Commission should deny AES Indiana's proposal to defer the Project development costs and accrue carrying costs for recovery in a future rate case. He said that, under this scenario, ratepayers should not be responsible for any return "on" or "of" the Project development costs because ratepayers will not benefit from these expenditures if the Project is not approved. He said Petitioner—not its ratepayers—made the decision to incur these expenditures, and the Project development costs should not be risk free. He also said that if the Commission rejects AES Indiana's proposed Project, the related Project development costs would not meet the "used and useful" standard.

Mr. Latham testified that the OUCC considered environmental sustainability in its review. He said Petitioner indicates the conversion of Units 3 and 4 from coal to natural gas will result in significant reductions in most criteria air pollutants, mercury, and carbon dioxide ("CO_2") emissions. He said the conversion will also eliminate the CCR waste streams. He added that this reduction in emissions should result in reduced environmental compliance costs.

Mr. Latham also discussed the IRP and opined that the Project is identified as a component of the Short-Term Action Plan and is consistent with the 2022 IRP and the 2024 IRP update.

OUCC witness Roopali Sanka addressed the attributes of reliability, resiliency, and stability as referenced in Ind. Code § 8-1-2-0.6 and opined that that the Project supports the reliability, resiliency, and stability attributes of the Five Pillars of Ind. Code § 8-1-2-0.6. She added that keeping this substantial, dispatchable generation facility in operation supports reliability, stability, and resiliency for AES Indiana and its customers.

7. **<u>Intervenor Evidence</u>.** Intervenor REI is a trade association formed in Indiana in 2020 by representatives of Alliance Resource Partners, LP ("Alliance") and Hallador Energy Company ("Hallador"). Alliance is a diversified coal supplier and marketer in Indiana and other states. Hallador's wholly owned subsidiary, Sunrise Coal, LLC ("Sunrise"), is also an Indiana coal producer. Both coal companies provided coal to AES Indiana's Petersburg coal units. REI witnesses testified in opposition to AES Indiana's proposal to repower Petersburg Units 3 and 4 with natural gas. REI requested the Commission deny AES Indiana's application for a CPCN or, at a minimum, abate or continue the proceedings.

Both Ms. Medine and Mr. Nasi opined that aspects of AES Indiana's Petersburg Repowering Project proposal do not meet the Indiana statutory criteria for a CPCN and are not just and reasonable.

Ms. Medine opined that there is tremendous regulatory uncertainty at this time that makes significant capital investments highly risky and, in this case, unnecessary and inappropriate. She argued that AES Indiana provided no compelling reason (including no economic reason) why the units cannot continue to operate as is until there is greater certainty regarding the long-term viability of the repowered gas units. She stated that no law is compelling AES Indiana to repower the facilities in the proposed timeframe. She said AES Indiana has until 2030 to determine whether to repower the Petersburg units and testified that it is not in the public interest to rush to a decision that could leave ratepayers with additional stranded costs. Ms. Medine stated that there is uncertainty related to EPA's Good Neighbor Rule, which she argued could affect the operation of Unit 4 during the summer ozone season without a SCR. She said Mr. Nasi has explained that litigation is already pending that could completely outlaw the refueling decision, make the use of the repowered units unlawful as early as 2030, or alter the capacity factors and inputs that determine whether the repowered facility complies with the final regulations.

Ms. Medine also opined that AES Indiana's IRP must be adjusted to remove what she characterized as biased assumptions driving the selection of the repowering as the Preferred Plan, to neutralize AES Indiana's preference for repowering to award extra compensation to AES Indiana's executive team for reducing coal reliance, and to correct erroneous inputs that skew the outcome. She contended that AES Indiana concluded in its 2022 IRP that repowering Petersburg Units 3 and 4 was the preferred plan to support corporate goals established by AES Indiana's parent company, The AES Corporation, to exit coal by 2025 rather than pursuing the least cost option for the benefit of customers.

She argued that AES Indiana failed to adequately demonstrate its proposal aligns with the Five Pillars of Ind. Code § 8-1-2-0.6. She said that AES Indiana failed to consider the alternative of offering the Petersburg Units for sale to a third party to mitigate rate impacts on ratepayers and preserve the units' ability to continue to contribute to the region's need for energy and capacity.

Ms. Medine asserted that AES Indiana's omitted "knowable expenses" largely related to the firm transportation of natural gas in AES Indiana's Affordability analysis performed for the 2022 IRP and 2024 IRP update. She argued that AES Indiana has not arranged for firm transportation of natural gas that will withstand severe weather and force majeure events. Mr. Nasi pointed to a 2021 winter storm in Texas to support his concerns with the reliability of natural gas units.

Ms. Medine opined that, under Ind. 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 customer classes. She also argued that AES Indiana's NPV analysis does not account for "sunk costs" or conduct a rate impact analysis. Ms. Medine claimed that AES Indiana residential customers have the second highest customer bills in Indiana since 2014. She also claimed 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. She also contended the repowering of the Petersburg units is not an ideal long-term solution. She criticized the load forecast, the NPV analysis, the natural gas pricing included in the IRP, and contended the capacity factor shown in AES Indiana witness Miller's direct testimony demonstrate that the Petersburg on coal option is more economic than repowering the units because Petersburg on coal has a higher capacity factor.

Mr. Nasi opined that AES Indiana's proposal does not satisfy Indiana's criteria for the issuance of a CPCN and is not just and reasonable under current regulatory and market conditions. He and Ms. Medine also contended that the uncertainty in environmental regulations has the potential to create stranded costs for AES Indiana.

Mr. Nasi testified that, after AES Indiana filed its Petition in this proceeding, the EPA released final rules on May 9, 2024 establishing carbon dioxide limits for existing coal units, like the Petersburg units at issue, and existing gas-fired steam generating units such as those that would remain at the site upon the AES Indiana fuel switch from coal-to-gas. He contended EPA's final GHG NSPS significantly impact AES Indiana's proposal in this proceeding, yet noted again, as was argued in REI's Motion for Summary Judgment, that AES Indiana failed to supplement its case-in-chief to demonstrate whether and how its proposal is consistent with EPA's final rules.

Mr. Nasi opined that AES Indiana's proposal is based on legally questionable assumptions that, if wrong, will result in a Repowering Project that could leave ratepayers with stranded costs and a gas-fired asset that does not deliver baseload power. He contended the final rule does not compel fuel switching, but AES Indiana appears to be choosing a fuel switching compliance strategy. He testified that it remains to be seen what provisions the Indiana state plan to be submitted to EPA for approval of CO_2 specific standards of performance will include, including whether Indiana's plan will include provisions that would incent or discourage conversion of existing coal plants to natural gas. Mr. Nasi questioned whether conversion results in "reconstruction" of the facility, which would subject the units to other performance standards. Mr. Nasi also discussed legal instability, noting that the final rule is being challenged in court, could be stayed in the near term, and could be struck down in the longer term. He opined that the final rule is legally suspect.

Mr. Nasi argued that a Commission decision granting the requested CPCN would be premature for two reasons: first, insufficient information has been made available to assess the highly complex legal and technical issue of whether the conversion will effectively excuse AES Indiana from complying with EPA requirements that would apply if the Project constitutes reconstruction; second, the ultimate determination of what regulatory requirements will apply to the Units will not be known until Indiana develops a plan for CO_2-specific standards of performance in response to EPA's final rule. Mr. Nasi asserted that AES Indiana will not be harmed by waiting to see how things "shake out in the courthouse" regarding EPA's rule and, even if the rule is upheld, waiting to see what makes it into the Indiana state plan. REI witnesses Medine and Nasi claimed that AES Indiana should delay repowering Petersburg Units 3 and 4 because the GHG NSPS would not force Petersburg Units 3 and 4 to be repowered until January 1, 2030, which REI witness Nasi claimed would provide AES Indiana "plenty of time" to continue to operate the Units on coal and still complete a repowering prior to the January 1, 2030 deadline.

Mr. Nasi argued that the only outcome for this proceeding that squares the environmental regulations with the Five Pillars is to abate this proceeding or to deny AES Indiana's request at this time. He stated that AES Indiana can continue to run the Petersburg Units without jeopardizing reliability and delay its refueling plans until the environmental regulations are final and non-appealable.

Mr. Nasi also raised a concern regarding the Commission's statewide energy plan. He noted that Ind. Code § 8-1-8.5-3(c) requires the Commission to conduct and consider its own analysis of the long-range energy needs of the state in acting on a request to construct new electric generation. at 16. He said the Commission's General Administrative Order ("GAO") 2018-2 sets out a procedure Commission staff should follow each year to prepare the statewide analysis. He stated that there is not a current statewide analysis that meets the requirements of the Indiana Code. He testified there are at least two important components required by the Indiana Code concerning the statewide analysis that do not exist and for which AES Indiana has produced no evidence: first, the optimal extent, size, mix, and general location of the generating plants; and second, the optimal arrangement for statewide or regional pooling of power and arrangements with other utility and energy suppliers to achieve maximum efficiencies for the benefit of Indiana. He opined that it would be unfair for the Commission to approve this Repowering CPCN request in the absence of information about the Commission's views on these issues.

Mr. Nasi acknowledged that Ind. Code § 8-1-8.5-5(b)(2)(B) provides that the Commission may approve a CPCN in the absence of a Commission statewide analysis if it finds the Project is consistent with the utility-specific proposal submitted and approved. However, he again opined that AES Indiana's IRP is flawed in many important aspects.

8. Petitioner's Rebuttal Evidence.

A. Response to OUCC Testimony on IRP Development and Analysis. Mr. Miller clarified that AES Indiana does not have a goal regarding reliance on coal generation for its capacity and energy needs. He said The AES Corporation has sustainability targets; however, these targets did not impact AES Indiana's IRP analysis and the decision to repower Petersburg Units 3 and 4 to natural gas. He explained that both the 2022 IRP and the 2024 IRP update objectively evaluated the strategies for Petersburg across the Five Pillars. He added that the results of the 2022 IRP and 2024 IRP update identified the Petersburg Repowering Project as the most affordable, reliable and sustainable option for customers.

B. The AES Corporation Environmental, Social and Governance Goals and AES Indiana's 2022 IRP. Mr. Bigalbal argued that Ms. Medine's allegations regarding The AES Corporation are not based on a reasonable factual or analytical foundation, pointing out that she couches her arguments with speculative phrases such as "it appears," "may have," or "may or may not have." He also discussed how Ms. Medine's discussion of The AES Corporation announcement omits key language and therefore is incomplete. He showed the complete announcement was: "The Company intends to exit coal by 2025, through a combination of asset sales, fuel conversions and retirements, *while maintaining reliability and affordability, and subject to necessary approvals*." Pet. Ex. 2 at 5. Mr. Bigalbal also stated that AES Indiana explained throughout its IRP process that the global parent company's targets would not influence the analysis or its outcomes and that the IRP is an objective analysis.

Mr. Bigalbal also responded to Ms. Medine's contentions that the AES Corporation executive leadership team's compensation is tied to reducing coal generation. He said that the AES Corporation's executive leadership team's compensation is based on four elements: base salary, performance incentive plans, long-term compensation, and retirement and health and welfare benefit. He testified that one of the many components of the long-term compensation element for the award of restricted stock units is attainment of long-term environmental, social, and governance ("ESG") goals and added that, while the attainment of long-term ESG goals is determined using several measures, one such measure is the reduction of gigawatt hours from coal generation across The AES Corporation's global portfolio. He said the integration of ESG performance metrics into the incentive plans for senior executives is common amongst S&P 500 and Russel 3000 companies, of which The AES Corporation is a member.

Mr. Bigalbal opined that AES Indiana demonstrated in its 2022 IRP and in the 2024 IRP update that the Petersburg Repowering Project performs favorably across the Five Pillars in all scenarios. He stated that low gas prices combined with the high fixed cost of operating coal plants make coal generation less competitive compared to alternatives, like gas.

Mr. Bigalbal testified that AES Indiana engaged in a robust stakeholder process in which it solicited and considered feedback from customers with a wide range of beliefs and interests associated with AES Indiana's generation portfolio. He said the 2022 IRP analysis used reasonable inputs and assumptions that were stress tested to account for variability in future economic and regulatory conditions, which was described in more detail in AES Indiana witness Miller's rebuttal testimony. Mr. Bigalbal testified that the Petersburg Conversion strategy performed better than keeping it on coal across the Five Pillars, under all scenarios, and is the least cost option for customers. He added that The AES Corporation's goals had no bearing on the outcome of this objective analysis.

Finally, Mr. Bigalbal testified that the Petersburg Repowering Project is estimated to save customers $281 million to $437 million and reduce emissions compared to operating the units on coal. He again cited Mr. Miller's direct testimony, including his Figure 6, which compares the 2022 IRP to the affordability results from the 2024 IRP Update using 20-year and ten-year PVRR periods:

Figure 6. 2024 IRP Update Affordability Results[31]

20-yr PVRR	2022 IRP ($M)	2024 IRP Update ($M)
No Early Retirement	$ 9,572	$9,449
Petersburg Conversion to Natural Gas (est. 2026)	$ 9,330	$9,168
Both Petersburg Units Retire (2026/2027 and 2028/2029)	$ 9,618	$9,596
Clean Energy Strategy - Both Petersburg Units Retire and Replaced with Wind, Solar and Storage (2026/2027 and 2028/2029)	$ 9,711	$9,604
10-yr PVRR	**2022 IRP ($M)**	**2024 IRP Update ($M)**
No Early Retirement	$ 5,815	$5,513
Petersburg Conversion to Natural Gas (est. 2026)	$ 5,750	$5,513
Both Petersburg Units Retire (2026/2027 and 2028/2029)	$ 5,914	$5,641
Clean Energy Strategy - Both Petersburg Units Retire and Replaced with Wind, Solar and Storage (2026/2027 and 2028/2029)	$ 6,037	$5,638

Mr. Bigalbal noted that, according to Mr. Miller, Petersburg Conversion strategy is estimated to save customers $281 million over the IRP planning period without considering the specific requirements of the new GHG NSPS. Mr. Bigalbal testified that the new GHG NSPS did not change the outcome of this analysis, as the Petersburg Conversion strategy is now estimated to save customers $437 million over the IRP planning period following the new GHG NSPS.

Mr. Bigalbal testified that while the forming members of REI, which are coal suppliers of AES Indiana, have a financial self-interest in the continued operation of Petersburg on coal, AES Indiana's corporate values require AES Indiana to seek solutions that are in the best interest of customers, which is repowering Petersburg Units 3 and 4.

He concluded that any benefit the executive leadership team of The AES Corporation receives due to the Petersburg Repowering Project is ancillary to AES Indiana's decision to pursue the Petersburg Repowering Project.

C. <u>Alleged IRP Flaws</u>. Witnesses Bigalbal, Cooper, and Miller rebutted Ms. Medine's criticism of the coal cost assumption in the IRP analysis. Mr. Bigalbal pointed out that Ms. Medine failed to identify a proposed alternative, much less demonstrate that the alternative assumption is reasonable. Mr. Bigalbal also testified that Ms. Medine's claim that AES Indiana used "a single, inflated, artificial coal price input" in its 2022 IRP is not accurate. Mr. Miller testified that Ms. Medine's suggestion that AES Indiana did not reasonably address natural gas price uncertainty is without merit. Mr. Bigalbal and Mr. Miller explained that a stochastic analysis was performed on commodity prices to understand the range of outcomes given the uncertainty of future commodity prices and added that the repowering of Petersburg to natural gas performed very well in this analysis. Mr. Cooper explained that AES Indiana's stochastic analysis varied delivered coal prices, delivered gas prices, market power prices, load, and renewable energy generation for each of the strategies. He added that, in the stochastic analysis, the delivered coal prices ranged from \$0.73/MMBtu to \$9.56/MMBtu and in those same stochastic runs, natural gas prices ranged from \$0.82/MMBtu to \$22.54/MMBtu.

Mr. Cooper disputed REI's description of the AES Indiana coal price curve. He stated that, in 2022, coal prices were at relatively high levels due to world events and the inelasticity of coal production in the eastern United States and transportation in the face of these events. He said AES Indiana was in the market at the time and used its second lowest offer on a delivered basis (not the second highest as misstated by Ms. Medine) as the starting point for the coal curve in the IRP (i.e., the price at which AES Indiana could have purchased its next ton of coal). He stated that the IRP coal price curve was for fuel delivered to the plant. He added that delivery costs can have a material impact on the cost of fuel consumed at the plant—in AES Indiana's case, as much as 20% or more for Illinois Basin coal.

Mr. Cooper, Mr. Bigalbal, and Mr. Miller testified that Ms. Medine used actual data from 2022 to call into question the coal price forecast AES Indiana used in its 2022 IRP. Mr. Bigalbal stated that the coal price values AES Indiana included in its 2024 IRP update are similar to the current market coal prices Ms. Medine included in her testimony. Therefore, he opined that the updated economic analysis presented by AES Indiana witness Miller in his direct testimony demonstrates that using coal prices similar to the current market coal prices Ms. Medine included in her testimony supports the Petersburg Repowering Project. Mr. Cooper also testified that AES Indiana, in its updated curve, accurately captures the decreasing coal price trend noted by Ms. Medine.

With respect to whether the Petersburg Repowering Project is the least-cost option, Mr. Bigalbal testified that the Petersburg gas conversion is relatively inexpensive at less than \$300 per kilowatt ("kW") to maintain the existing generation of over 1,000 MW. He said that the estimated cost of a simple cycle gas turbine (which is commonly used as the least-cost option for new capacity) is between \$700/kW and \$1,150/kW. He testified that the conversion will lower exposure to future environmental regulations by significantly reducing air emissions, including carbon dioxide, eliminating coal combustion residuals, and reducing the amount of water needed at the facility. He stated that the primary cost savings for the conversion from coal to natural gas are the fixed operations and maintenance cost and the reduction in CO_2. Mr. Bigalbal added that, in the 2024 analysis AES Indiana performed at the request of REI via the discovery process, which includes compliance with GHG NSPS, the cost savings were even more significant due to the cost of complying by cofiring 40% natural gas.

Mr. Cooper testified that AES Indiana did not seek to disadvantage coal in its IRP analysis, noting that, by way of example, there were two scenarios in the 2022 IRP that contemplate a future with more stringent environmental regulations on generators and fuel production. In its "Aggressive Environmental" scenario, AES Indiana used the high natural gas price curve while using the base coal curve; he said not using a high coal curve in that scenario is an advantage for Petersburg remaining on coal.

Mr. Bigalbal responded to Ms. Medine's contention that any new investment in natural gas generation should be justified based upon a firm retirement date of 2040 due to The AES Corporation's 2040 Net Zero plan. He stated that, as a regulated utility, AES Indiana follows the applicable laws and regulations in place when making its resource decisions. He said Indiana law and regulations require investor-owned electric utilities to conduct an IRP process to determine the future of its generation portfolio. He stated that AES Indiana is committed to acting in the best interest of its customers by complying with Indiana laws and regulations, including maintaining a portfolio that is consistent with the Five Pillars. He said AES Indiana has not and will not include any inputs or establish limitations in its IRP analysis because such items are goals of its parent organization.

Mr. Bigalbal quantified the difference between depreciating over 20 years (as reflected in AES Indiana's analysis) versus 13 years (as proposed by REI) and showed this approach would not change the outcome of the financial analysis.

In response to Mr. Nasi's assertion that AES Indiana's IRP and decision to repower reflects a singular view, Mr. Miller testified that the Petersburg Repowering Project offers one-for-one replacement natural gas capacity for Units 3 and 4. He said these units will maintain dispatchability, thereby preserving reliability for AES Indiana customers, the state of Indiana, and MISO.

In response to Ms. Medine's contention that the 2022 IRP reflects an over-reliance on renewables, Mr. Miller testified that 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. He added that, given the challenges for citing wind in Indiana, AES Indiana 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. Mr. Miller added that Ms. Medine is focused on the year 2032, which is when Harding Street Units 5, 6, and 7 (approximately 600 MW of capacity) are assumed to be retired. He said 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. He stated that the 2030 planning period is far beyond the Short-Term Action Plan window (2023 through 2027) and added that AES Indiana will conduct another IRP in 2025 that reevaluates strategies for this period. Mr. Miller said this update will include assumption updates that account for renewable energy availability and accreditation.

With respect to REI's testimony regarding sunk costs, Mr. Miller clarified that AES Indiana is not retiring Petersburg. He explained AES Indiana is repowering the units to operate on natural gas. He explained that the recovery of the undepreciated costs for Petersburg is the same whether the units remain on coal, are retired, or are repowered to natural gas. He added that the net present value analysis provided in the IRP concerning the treatment of undepreciated costs for the Petersburg Repowering is correct.

Mr. Miller also responded to Ms. Medine's comment that there appears to be no financial benefit given the equivalent NPV for the ten-year period. He stated that Ms. Medine's claim fails to account for the demonstrated risk that remaining on coal at Petersburg poses to AES Indiana customers. He said AES Indiana demonstrated in its 2022 IRP that, as regulation of CO_2 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. He added that, after accounting for the 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. Mr. Miller showed that when the GHG NSPS are considered, repowering the units to natural gas costs nearly $100 million less than keeping the units on coal over that ten-year period. He opined that the Petersburg Repowering Project provides AES Indiana customers with a reasonable hedge against the cost to comply with pending regulation on CO_2. Mr. Miller added that Ms. Medine also failed to consider the sustainability benefits of repowering the units to natural gas which will result in half the CO_2 per MWh generated, eliminate SO_2 and coal combustion waste, and greatly reduce particulate matter (all of which come with associated costs). Information about these environmental benefits is contained in Figures 3 and 11 of Mr. Miller's direct testimony, which are reproduced above.

Mr. Miller also testified that the Commission Director's draft report does not support REI's view that AES Indiana's 2022 IRP is flawed. Mr. Miller testified that AES Indiana followed the IRP Rules contained in 170 IAC 4-7 in conducting its 2022 IRP and said this includes appropriately evaluating the affordability pillar by using both the ten-year and 20-year PVRR and the present value of revenue requirement for each candidate portfolio in dollars per kWh delivered with interest rate applied and updated the IRP for relevant market and environmental regulation changes to confirm the repowering remains consistent with the IRP and reasonable.

With respect to upstream emissions from natural gas, Mr. Miller testified that AES Indiana limited the analysis to "inside the fence" emissions or emissions directly associated with combustion processes and power production at the plants. Mr. Miller indicated that upstream emissions are difficult to quantify and open the door for contention among stakeholders. If AES Indiana were to include upstream emissions for power production using natural gas, then AES Indiana would also have to include them for power production using coal, also negatively impacting the strategy that Ms. Medine prefers.

In response to Ms. Medine's testimony regarding capacity factors, Mr. Miller testified that Ms. Medine based her assessment on only the energy revenue generated from coal operation versus natural gas operation and thereby failed to see the whole picture. He noted that AES Indiana's analysis included higher natural gas prices compared to coal prices, which would drive more coal-fired operation, and therefore, with lower prices available, the analysis shows Petersburg operating on coal generates more energy revenue over the planning period versus operating the units on natural gas.

Mr. Miller also testified that energy revenues alone do not tell the full story; he stated that the primary cost savings to AES Indiana customers come from the fixed O&M savings that result from repowering the units. After the 2024 IRP Update, O&M savings were estimated to be $683 million in fixed and $161 million in non-fuel variable costs. Mr. Miller pointed to Figures 9 and 10 in his direct testimony as a complete picture of the various costs and benefits of repowering the units.

Figure 10. Estimated mitigation costs (2022 dollars) for the "Candidate Portfolios" from 2022 IRP Reliability Analysis

	No Early Retirement	Petersburg Conversion to Natural Gas (est. 2025)	Both Petersburg Units Retire (2026 and 2028)	Clean Energy Strategy – Both Petersburg Units Retire and Replaced with Wind, Solar, and Storage (2026 and 2028)
GFM Inverter Premium ($M)	$6	$5	$2	$6
Additional BESS ($M)	$120	$131	$20	$52
Additional Synchronous Condensers ($M)	$0	$0	$135	$871
Estimated Reliability Cost ($M)	$126	$136	$157	$929

D. <u>EPA GHG NSPS</u>. Mr. Bigalbal testified that a compliance plan specifically tailored to the recently published GHG NSPS was not considered in the 2022 IRP. He said the outcome of the 2022 IRP was determined based on economics and uncertainty, including environmental regulatory uncertainty, at the time the IRP analysis was performed. Mr. Bigalbal and Mr. Miller testified that the uncertainty of any GHG regulations was modeled in the 2022 IRP as a cost of compliance for carbon dioxide emissions of $6.49/ton which was applied to both coal and natural gas. Four GHG regulation scenarios were modeled, and Mr. Bigalbal and Mr. Miller testified that the repowering with natural gas outperformed staying on coal in all four scenarios. They opined that this approach reasonably addressed GHG regulatory uncertainty in the 2022 IRP. Mr. Miller said that the final GHG NSPS does not change this conclusion; rather, he opined that the impact of the final GHG NSPS makes repowering Petersburg an even better choice.

Ms. Collier testified that Mr. Nasi's statement that AES Indiana appears to be choosing a fuel switching compliance strategy in the context of EPA's final GHG NSPS is not accurate. She said that EPA's GHG NSPS are not the driver for AES Indiana's proposal to repower Petersburg Units 3 and 4 and that the proposal to repower Units 3 and 4 was based on AES Indiana's IRP analysis.

Ms. Collier testified that, under the new GHG rules, 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 an application of 40% natural gas co-firing, resulting in capital investment. She noted that, 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.

Ms. Collier explained that by repowering Units 3 and 4 and eliminating their capability to combust coal before January 1, 2030, the Units will be considered existing natural gas-fired EGUs under the final greenhouse gas regulations subject to emissions limits based on routine methods of operation and maintenance, as established in a State Plan. She stated that as such, additional capital investment or operational expenses beyond routine methods of operation and maintenance is not expected to be required.

Ms. Collier stated that, based on these final standards of performance under the GHG NSPS, the repowering of Units 3 and 4 is not significantly, or even partly, adversely impacted by the GHG NSPS; however, she stated that the continued operation of the Units on coal would be adversely impacted.

Mr. Miller testified that, 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 GHG NSPS. He said that this analysis demonstrates that the Petersburg Repowering Project 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) under the GHG NSPS when compared to the 2022 IRP results because the new rules contain more aggressive compliance requirements for coal versus gas. He said this analysis of the GHG NSPS makes it clear that coal faces significant regulatory risk whereas natural gas, with approximately half the CO_2 emissions per MWh generated compared to coal, is needed to maintain reliability and as a hedge in an environment of regulatory uncertainty.

Mr. Miller disagreed with REI's suggestion that the GHG NSPS somehow warrants a delay of this proceeding and testified that AES Indiana's direct testimony reasonably considers the impact of potential GHG regulation. He testified that the GHG NSPS increases the cost to keep Petersburg as a coal-fired resource because AES Indiana would be required to co-fire the units with natural gas starting in 2030 and then either install carbon capture and sequestration on the units by 2032 or retire the units by 2039. He noted that REI's witnesses do not mention this analysis, but OUCC witness Latham did consider it. Mr. Miller noted that REI had the opportunity to both review and respond to AES Indiana's analysis of the GHG NSPS, as the OUCC did, but failed to do so.

In response to REI's concerns about regulatory uncertainty, Mr. Rogers noted that the industry has long operated under uncertain environmental regulatory and political conditions. In order to fulfill its obligation to serve customers, AES Indiana must make long-term decisions in the presence of uncertainty. The Commission's integrated resource planning rule requires AES Indiana to consider existing environmental laws and future policies considering stakeholder feedback or future policies that have a high probability of being enacted when developing its reference case scenario. Mr. Rogers said AES Indiana's IRP appropriately considers risk through economic modeling and analysis of several scenarios, portfolios, and futures. Mr. Rogers testified that the economic modeling demonstrates that delaying a decision on whether to repower Petersburg Units 3 and 4 until environmental and political risk is supposedly reduced would expose AES Indiana customers to other reliability, affordability, and sustainability risks, including the ongoing higher cost of coal generating and capacity resources.

E. <u>IDEM's State Plan</u>. Ms. Collier testified that IDEM's state plan to implement GHG regulations would not affect whether the repowered units would be considered existing natural gas-fired generating units. States must set standards of performance for affected sources reflecting the degree of emission limitation that the EPA has determined to be the best system of emissions reduction ("BSER").

She testified that the EPA has established the subcategories for existing natural gas-fired steam generating units reflected in the requirements of the federal rule. She stated that the federal rule establishes that an existing unit is one that commenced construction on or before January 8, 2014. An EGU is considered to be coal-fired if it combusts, or is capable of combusting, coal on or after January 1, 2030. She said an EGU 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. She added that invocation of remaining useful life and other factors does not have the effect of modifying the subcategory structure or creating a new subcategory for a particular affected EGU, meaning that the EGU remains in the applicable subcategory. Ms. Collier also explained that Petersburg Units 3 and 4 will not be affected by the future rulemaking associated with the non-rulemaking docket mentioned by Ms. Medine because that docket is addressed to emissions of GHG from stationary combustion turbines and not steam generating units (i.e., boilers) like Peterburg Units 3 and 4.

In response to Mr. Nasi, Ms. Collier testified that Units 3 and 4 are existing EGUs. She stated that EPA did not include treatment of new EGUs as "transitional sources" in the GHG NSPS and clarified that EPA's requirements for new EGUs in the GHG NSPS are based on the date of the proposed rule (May 23, 2023).

Finally, Mr. Miller explained fixed O&M from converting the units from coal to natural gas will decrease by $683 million, regardless of the state's enforcement of the GHG NSPS. He said that 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. He also stated that, as demonstrated in the 2022 IRP Scenario analysis, AES Indiana and its customers will receive these fixed O&M cost reductions regardless of the future regulations analyzed.

F. REI's Proposed Repowering Delay. Mr. Bigalbal disputed REI's contention that AES Indiana could continue to run the Petersburg units on coal and "will have plenty of time" to repower Petersburg Units 3 and 4 in time for the 2030 deadline imposed by the GHG NSPS rule. He stated that the timeline associated with the current proposal shows it will take almost four years from the issuance of an RFP in March 2023 to achieve COD for both repowering units.

Mr. Bigalbal stated that AES Indiana would target to complete the repowering at least six months in advance of the January 1, 2030 deadline to ensure the units are repowered with sufficient time to meet the deadline and to account for delays in permitting, approvals, negotiations, supply chain, and construction. He noted that, even if AES Indiana was able to secure similar timing for the Petersburg Repowering Project, AES Indiana would have to terminate its existing EPC contract and issue a new RFP by mid-2025 in order to meet this January 1, 2030 deadline.

Mr. Bigalbal also discussed other risks associated with delaying the Petersburg Repowering Project to 2030 as suggested by REI. He stated that a delay completely disregards the increases in costs related to labor, materials, and supplies due to natural market fluctuations. He said these risks are compounded by the potential increase in the number of coal-to-natural gas conversions that will occur across the country due to the GHG NSPS. He noted that, whether or not the GHG NSPS survive the legal challenges against them, it is likely that many existing coal plant owners will seek to repower their units prior to the January 1, 2030 deadline. Thus, terminating the Project and seeking to repower the units in the future could significantly increase the cost of the project and extend the negotiation and construction timeline. Mr. Bigalbal stated that this would put meeting the January 1, 2030 deadline at risk because the limited number of experienced EPC contractors in the market will have many competing opportunities and the demand for their services as well as the demand for materials and supplies necessary to complete this conversion will increase.

Mr. Bigalbal testified that these factors further demonstrate that now is the optimal time to repower Petersburg Units 3 and 4 as AES Indiana entered into the EPC Agreement prior to the announcement of the GHG NSPS, thus avoiding any increase in costs or schedule delays related to an increase in EPC contractor or materials and supplies demand due to the GHG NSPS.

G. <u>REI's "Reconstruction" Argument</u>. Ms. Collier testified that IDEM has already determined that the repowering of Units 3 and 4 from coal-fired to natural gas-fired units is not considered reconstruction during the finalized air permitting process for the repowering of Units 3 and 4 from coal-fired to natural gas-fired. Mr. Bigalbal testified that, under current environmental regulations, a coal-fired generating unit in operation or that started construction prior to January 2014 may convert to natural gas without triggering NSPS and will continue to be considered an existing source subject to NSPS for existing sources if it does not increase emissions or the cost to make the modification does not exceed 50% of the cost of new construction.

Mr. Bigalbal testified that the cost to repower Units 3 and 4 from coal to natural gas is significantly less (well under 50%) than the cost to build a comparable new facility (i.e., a new natural gas-fired boiler of similar size), according to Sargent & Lundy. Mr. Bigalbal testified that the best estimate of the Petersburg Repowering Project (both units) cost is $293.2 million. He said Sargent & Lundy estimates that it would cost $400 to $500 million to construct an entirely new facility comparable to either repowered Units 3 or 4. He testified that the Petersburg Repowering Project is estimated to be approximately 30% to 38% of the cost of constructing an entirely new comparable facility; therefore, he concluded that AES Indiana's proposed repower does not meet the definition of "reconstruction."

AES Indiana witness Collier testified that even if the project were considered "reconstruction" and subject to the NSPS for reconstructed steam electric generating units, no additional capital investment or operational expenses would be needed to meet that standard (1,800 lb CO_2/MWh-gross). Mr. Bigalbal stated that an analysis completed by Sargent & Lundy shows the emissions are expected to be below 1,400 pounds/MWh-gross.

Ms. Collier explained that there is no basis for Mr. Nasi's suggestion that the 50% threshold for something to be considered "reconstruction" may not apply and added that EPA has not proposed such a future regulation to date. Ms. Collier testified that the EPA is clear in both the final rule preamble and the regulatory text that fuel type subcategorization under the GHG NSPS for existing sources is based on the fuel being burned on and after January 1, 2030, considering conversion of existing units from coal to natural gas. Mr. Bigalbal added that REI's prediction that EPA will fundamentally change the regulations from those promulgated less than two months ago in a way that would materially negatively impact repowered Units 3 and 4 is purely speculative.

He stated that, where regulatory uncertainty exists, AES Indiana must make decisions based on a reasonable range of possibilities, which it had done through the 2022 and 2024 IRP analysis.

Ms. Collier testified that there is no indication that EPA plans to develop more stringent standards for existing or converted gas fired steam generating EGUs, and the state of Indiana has not indicated any plans to develop greenhouse gas standards outside of the State Plan required by the GHG NSPS.

Mr. Bigalbal testified that Ms. Medine did not explain her statement that repowering Units 3 and 4 before 2030 could be unlawful and added that Mr. Nasi's testimony on this point was also vague.

H. Good Neighbor Rule. Mr. Miller disagreed with REI's witnesses that AES Indiana did not consider the Good Neighbor Rule in its proposal. He stated that, in its 2022 IRP, AES Indiana assumed NO_x prices increased to $14,000/ton in 2027 to account for potential changes in the Good Neighbor Rule, and, even with those NO_x prices, AES Indiana's proposed repowering was still the most affordable option.

Ms. Collier testified that, even if the Good Neighbor Rule were to eventually be overturned based on the merits of legal challenges, any replacement EPA rule would be subject to a public notice and comment period following the well-established administrative rulemaking process with proper implementation timeframes. She stated that, regardless of the specific CSAPR requirements that may eventually apply, the repowering of Petersburg Units 3 and 4 will significantly reduce emissions of NOx, facilitating compliance with the requirements of a NOx Ozone Season trading program as compared to operation on coal.

I. Reliability of Natural Gas Versus Coal. Mr. Cooper disagreed with witness Medine's contention that AES Indiana has not arranged for firm transportation of natural gas that will withstand severe weather and force majeure events. Mr. Cooper explained that AES Indiana has considerable experience delivering natural gas, including during extreme weather events like Winter Storm Elliot, which REI witness Medine referenced. He stated that the firm transportation for the Petersburg plant is directly connected to the Rockies Express Pipeline, Trunkline Gas, Texas Gas Transmission, and Tennessee Gas Pipeline, among others, and, as a result, AES Indiana has provided for pipeline diversity as well as supply region diversity.

Mr. Cooper observed that coal plants have more systems related to the production of energy compared to natural gas plants, including fuel handling systems, and can be affected by extreme cold weather. He stated that, during extreme cold weather events, coal is difficult to handle because it can freeze and this causes plugged chutes and silos, which can derate the units and put them at a greater risk of tripping than a gas-fired unit on the fuel side.

Regarding overall supply, Mr. Cooper testified that the inelasticity of coal supply can and has also caused issues. Pointing to REI witness Medine's reference to the slow coal industry response in 2022 to higher post-COVID demand, Mr. Cooper explained that during the period leading up to Winter Storm Elliot in December 2022, coal plants in Indiana and elsewhere, including Petersburg, were forced to take steps to preserve coal inventory by reducing burns because the coal industry was unable to deliver enough coal. He said natural gas was the fuel that supplied the MWh when coal availability was inadequate.

Mr. Cooper testified that Ms. Medine's reference to load growth as a reliability issue related to the repowering of Petersburg conflates now-anticipated industry-wide load growth and decisions to retire or not retire coal units by other utilities. He explained that the examples Ms. Medine cited involved coal plant retirements and reiterated that AES Indiana is not proposing to retire Petersburg Units 3 and 4; the Petersburg Repowering Project maintains the same capacity achieved with the units on coal. Mr. Miller added that repowering the plant poses very low execution risk compared to retiring and replacing the units with other resources like wind, solar and storage. He noted that AES Indiana has already successfully demonstrated a coal-to-gas conversion with AES Indiana's Harding Street Steam Units 5, 6, and 7.

Mr. Miller explained that, in the 2022 IRP, AES Indiana assessed a range of load sensitivities in the deterministic IRP Scenario Analysis. He opined that the load forecast reflected in the IRP was reasonable at the time the IRP analysis was performed. He stated that, consistent with the Commission's IRP rules, AES Indiana appropriately updated the load forecast and other assumptions for the 2024 IRP update discussed in his direct testimony. He opined that, in making this update, AES Indiana reasonably captured the most contemporary load forecast for the analysis.

J. Third-Party Sale. Mr. Bigalbal also addressed Ms. Medine's suggestion that AES Indiana should have, but failed to, consider selling Petersburg Units 3 and 4 to a third-party and her reference to Hallador's purchase of Merom Generating Station as precedent for a private investor to acquire a coal plant that a utility desires to retire. Mr. Bigalbal noted that Hallador, a founding member of REI, has no previous experience operating a coal plant. Mr. Cooper testified that this means that such third-party ownership would not be "less risk" for AES Indiana customers.

Mr. Miller testified that, if AES Indiana were to sell the Petersburg Units, AES Indiana would have to replace that capacity by either constructing new resources or entering into a purchase power agreement for capacity and energy, likely at a higher cost than the proposed repowering. He opined that REI's contention that AES Indiana 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. Mr. Bigalbal stated that AES Indiana has no plans to retire Petersburg Units 3 and 4, as the units are valuable capacity and energy resources that will continue to serve AES Indiana's customers with affordable and reliable service.

AES Indiana witnesses Cooper (Section 4) and Miller (Section 6) also argued that Ms. Medine misinterpreted Ind. Code § 8-1-8.5-5(e) as requiring AES Indiana to consider selling to a third party under Indiana state statute, stating that this particular situation does not require that.

K. Five Pillars. AES Indiana's witnesses disputed REI witnesses' testimony on what they should have done in order to fully consider the Five Pillars of Ind. Code § 8-1-2-0.6: reliability, affordability, resiliency, stability, and environmental sustainability. We will discuss the testimony on this matter in further detail below.

L. **<u>Statewide Energy Plan</u>.** In response to Mr. Nasi, Mr. Miller testified that Ind. Code § 8-1-8.5-5(b) states that one of the findings the Commission must make before granting a CPCN is that the proposed project is consistent with either the Commission's statewide generation expansion analysis ("Statewide Analysis") or the utility's current IRP. Here, Mr. Miller opined that the proposed repowering project is consistent with both its current IRP and the Commission's 2018 Statewide Analysis.

M. **<u>Accounting and Ratemaking</u>.** Mr. Rogers testified that AES Indiana agrees with the OUCC on all issues except the OUCC's proposal regarding AES Indiana's recovery of project development costs in the event the Commission does not approve AES Indiana's CPCN request in this Cause.

Regarding project development costs, Mr. Rogers stated that, if the Commission denies AES Indiana's CPCN request in this Cause, AES Indiana has still made project development expenditures to prudently execute its IRP Short-Term Action Plan to economically secure capacity and generation to serve AES Indiana customers. He opined that these costs should still be recovered through rates as they are reasonable in amount, clearly identified in his direct testimony, and were expended to achieve AES Indiana's preferred generation and capacity based on sound resource planning processes and methodologies.

9. <u>Commission Discussion and Findings</u>.

A. **<u>CPCN</u>.** Ind. Code § 8-1-8.5-5 sets forth the criteria for approval of a utility-specific generation proposal. The Commission must make findings as to: 1) the best estimate of the project cost; 2) whether the proposal is consistent with our statewide analysis or a utility-specific proposal; and 3) whether the public convenience and necessity requires or will require the project. The Commission must also consider alternatives to the proposed generation project as required by Ind. Code § 8-1-8.5-4. We address each of these provisions below.

i. **<u>Best Estimate</u>.** Mr. Bigalbal presented AES Indiana's best estimate for the cost of the Petersburg Repowering Project and discussed each component of the best estimate. In particular, he explained that the Project cost estimate of $293.2 million (excluding AFUDC and comprised of EPC cost, owner's costs, gas lateral cost, and contingency, per Pet. Ex. 1 at 22) was based on a turnkey EPC Agreement negotiated and entered into after AES Indiana conducted a competitive bidding process. Based on the information provided by Petitioner, OUCC witness Sanka stated that she had not identified issues or discrepancies with the best estimate and that she found Petitioner's proposed contingency and owner's costs to be reasonable. REI's witnesses did not challenge the best estimate.

Additionally, Ind. Code § 8-1-8.5-5(e)(1) provides that, for a project with a generating capacity of more than 80 MW, the Commission must find that:

> (A) the estimated costs of the proposed facility are, to the extent commercially practicable, the result of competitively bid engineering, procurement, or construction contracts, as applicable; and
>
> (B) if the applicant is an electricity supplier (as defined in IC 8-1-37-6), the applicant allowed or will allow third parties to submit firm and binding bids for the

> construction of the proposed facility on behalf of the applicant that met or meet all of the technical, commercial, and other specifications required by the applicant for the proposed facility so as to enable ownership of the proposed facility to vest with the applicant not later than the date on which the proposed facility becomes commercially available . . . .

The need for the Petersburg Repowering Project was originally defined in AES Indiana's 2022 IRP. According to Mr. Bigalbal, the cost of the Project EPC Agreement was determined through a competitive RFP and subsequent negotiation. Neither the OUCC nor REI's witnesses contested this testimony.

We find that AES Indiana conducted a competitive bidding process for the construction of the Project and allowed third-party bids for the construction of the Project. Further, we find that the estimated cost of the Petersburg Project is reasonable and well supported because it is the product of the competitive bidding process and a negotiated and executed EPC Agreement. Thus, we further find that the requirements of Ind. Code § 8-1-8.5-5(e) have been reasonably satisfied.

Based on the evidence of record, the Commission finds that AES Indiana has provided the best estimate of the cost of the Petersburg Repowering Project and approves the best estimate.

ii. <u>Consistency with Statewide Analysis or IRP</u>. Ind. Code § 8-1-8.5-5(b)(2) requires that the proposed construction, purchase, or lease of a facility for the generation of electricity be consistent with either the Commission's analysis for expansion of electric generating capacity or with a utility-specific proposal that we approve (e.g., the utility's IRP).

The Commission developed and published a Statewide Analysis in 2018. As we have previously noted, "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." *S. Ind. Gas & Elec. Co.*, Cause No. 45052, at 19 (April 24, 2019).

Mr. Miller testified that the repowering of Petersburg Units 3 and 4 is consistent with the SUFG's most recent Indiana Electricity Projections Report and the 2024 MISO Reliability Imperative report. Mr. Nasi did not contend otherwise.

The record reflects that the study period for AES Indiana's 2022 IRP was 2023-2042, giving due consideration to various options, potential risks, and stakeholder input. Based on extensive 2022 IRP modeling that evaluated very different potential futures, AES Indiana has determined that the strategy that converts Petersburg Units 3 and 4 to natural gas performed the best across the scenarios and potential futures. The 2024 IRP updates presented in Mr. Miller's direct and rebuttal testimony further demonstrate that the conversion of Petersburg Unit 3 and 4 from coal to natural gas is expected to perform well in terms of affordability, sustainability, reliability, resiliency, and stability. AES Indiana's stochastic analysis showed that 98 percent of the time converting the coal plant to natural gas was the more affordable option. Mr. Miller and Mr. Latham agreed that the Petersburg repowering is consistent with results of the 2022 IRP and the 2024 IRP updates.

We have considered REI's multitude of criticisms for AES Indiana's IRP and do not find them persuasive in our decision in this case, for the reasons explained further below.

1. <u>Commodity Costs</u>. Substantial evidence demonstrates that Ms. Medine's criticisms of the coal and natural gas assumptions do not withstand scrutiny. As discussed below, Ms. Medine ignored the 2024 Update, which, when taken into consideration, establishes that Ms. Medine's criticism is unfounded.

Mr. Cooper testified that AES Indiana was soliciting bids for coal supply at the time of the 2022 IRP stakeholder process and used the second most competitive, in other words, its second lowest offer on a delivered basis (not the second highest as initially misstated by Ms. Medine), as the starting point for the coal curve in the IRP as that would have been the price at which AES Indiana could have purchased its next ton of coal. The 2022 IRP shows AES Indiana's assumptions were responsive to stakeholder input. A stochastic analysis was performed on commodity prices to understand the range of outcomes given the uncertainty of future commodity prices and the repowering of Petersburg to natural gas performed very well in this analysis. As Mr. Cooper explained, AES Indiana's stochastic analysis varied delivered coal prices, delivered gas prices, market power prices, load, and renewable energy generation for each of the strategies. Moreover, the coal price values AES Indiana included in its 2024 IRP update are similar to the current market coal prices Ms. Medine included in her testimony. Thus, AES Indiana's updated economic analysis demonstrates that using coal prices that are similar to the coal prices Ms. Medine prefers supports the Petersburg Repowering Project. We find that AES Indiana's power and fuel price analyses in the 2022 IRP and 2024 IRP update are reasonable.

Ms. Medine's suggestion that AES Indiana intentionally disadvantaged coal lacks credible support. As noted elsewhere in this order, AES Indiana's IRP is the result of an extensive stakeholder process. The IRP's near-term coal pricing is based on competitive bids from the entities who sell coal to Petersburg, and the long-range curve is based on a reputable third-party source. As Mr. Cooper explained, two scenarios in the 2022 IRP contemplate a future with more stringent environmental regulations on generators and fuel production: "Aggressive Environmental" and "Decarbonized Economy."

Ms. Medine contended the Project should be justified based upon a retirement date of 2040 rather than the 20-year depreciable life used by AES Indiana, based on The AES Corporation's 2040 Net Zero plan. Mr. Bigalbal quantified the difference between depreciating over 20 years (as reflected in AES Indiana's analysis) versus 13 years (as proposed by REI) and showed this approach would not change the outcome of the financial analysis. This analysis demonstrates that rejection of the Petersburg Repowering Project is not warranted based on Ms. Medine's contention that any new investment in natural gas generation should be justified based upon a firm retirement date of 2040 due to the AES Corporation's 2040 Net Zero plan.

Ms. Medine's suggestion that AES Indiana did not reasonably address natural gas price uncertainty is also without merit. The stochastic analysis conducted as part of the 2022 IRP captured the volatility in natural gas and coal prices over 100 unique iterations. The analysis found that the Petersburg Repowering strategy performed better with lower risk when compared to keeping Petersburg on coal. The natural gas volatility modeled included natural gas prices as high as \$22.54/MMBtu and as low as \$0.78/MMBtu. The IRP shows AES Indiana also reasonably considered the PVRR ("P5") as the opportunity metric. The Petersburg Conversion strategy also maintains the lowest PVRR as an opportunity at the P5. Contrary to Ms. Medine's claim, the record reflects that 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.

2. **<u>Fuel Supply Reliability</u>.** The record shows that, to ensure fuel supply reliability for the Petersburg Repowering Project and corresponding generation supply for its customers, AES Indiana has secured firm transportation on the MGT pipeline equal to a maximum burn day — the highest priority level for service on the interstate natural gas system. MGT is an interstate pipeline that runs across the Petersburg Station property, and the transportation that AES Indiana has contracted will allow for deliveries from Rockies Express Pipeline, Texas Gas Transmission, and Tennessee Gas Pipeline. AES Indiana already conducts business on many of these pipelines with multiple suppliers. AES Indiana has provided for pipeline diversity as well as supply region diversity.

REI witness Medine argued that AES Indiana has not arranged for firm transportation of natural gas that will withstand severe weather and force majeure events. AES Indiana showed that it has considerable experience delivering natural gas, including during winter storms. AES Indiana witness Cooper noted that, while infrequent, force majeure events can be declared under Firm Transmission Agreements. He stated that, in AES Indiana's experience, working closely with interstate pipelines, and local distribution companies as applicable, on critical days has resulted in only de minimis impacts under the most extreme weather events. He reiterated that AES Indiana has provided for pipeline diversity as well as supply region diversity.

The evidence shows that, during Winter Storm Elliot, AES Indiana did not receive force majeures for its natural gas transportation, including on Texas Gas Transmission, and was able to deliver adequate gas to supply its units. The evidence further shows that coal plants have more systems related to the production of energy as compared to natural gas plants, including fuel handling systems, and can be affected by extreme cold weather, as well. During extreme cold weather events, coal can be difficult to handle because it can freeze. This can cause plugged chutes and silos which could derate the units and put them at a greater risk of tripping than a gas-fired unit.

The evidence also shows that the inelasticity of coal supply can cause and has caused issues. Pointing to REI witness Medine's reference to the slow coal industry response in 2022 to higher post-COVID demand, Mr. Cooper explained that, during the period leading up to Winter Storm Elliot in December 2022, coal plants in Indiana and elsewhere, including Petersburg, were forced to take steps to preserve coal inventory by reducing burns because the coal industry was unable to deliver enough coal. Natural gas was the fuel that supplied the MWh when coal availability was inadequate.

The record also shows that the Petersburg Repowering Project does not need dual-fuel capability, natural gas storage, or multiple pipelines directly feeding the plant to provide reliable electric service. Most issues requiring extraordinary measures and costs for onsite storage or other redundancy investments are related to known constraints. Mr. Cooper testified that there are no such issues or constraints with the Petersburg Repowering Project.

Both coal and natural gas supply and transportation can experience issues during severe weather or other force majeure events. The evidence demonstrates that AES Indiana has taken reasonable and prudent actions to ensure a reliable natural gas supply for the Project, including capitalizing on a location that is served by several pipelines with access to several natural gas supplies and contracting for firm gas transportation. The evidence indicates that the potential for natural gas supply issues at Petersburg has been prudently managed through use of supply diversity and region diversity.

3. Load Forecast. REI witness Medine also raised the issue of load growth as a reliability concern related to the repowering of Petersburg. She cited recent anticipated industry-wide load growth and decisions regarding retirement of coal units by other utilities as support for her concern. The record reflects that AES Indiana assessed a range of load sensitivities in addition to a stochastic analysis to further assess risk associated with load variability and volatility. AES Indiana's rebuttal evidence reiterated that it is not proposing to retire the Petersburg units. Rather, AES Indiana is proposing to replace the coal-fired capacity with natural gas-fired capacity on a one-for-one basis. The examples cited by Ms. Medine, on the other hand, involve delays of coal plant retirements. Given AES Indiana's successful coal-to-gas conversion at its Harding Street facility, the Petersburg Repowering Project poses a low execution risk compared to retiring the units and replacing them with other resources. In contrast, the delayed retirement examples cited by Ms. Medine involve replacements with renewable resources that have encountered development challenges. The evidence of record reflects that AES Indiana reasonably evaluated the risk of the strategies for Petersburg using a range of load forecasts, including forecasts that were much higher and much lower than the base case load forecast.

4. Renewables. REI witness Medine also criticized the volume of new renewable resources included in AES Indiana's IRP in light of challenges with renewables development. The evidence shows that AES Indiana reasonably 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. Ms. Medine's focus was on the year 2032, which is when Harding Street Units 4, 5, and 6 (approximately 600 MW of capacity) are assumed to be retired, at which point the 2022 IRP chose a large volume of renewables to replace these units in the 2030s. We note that the 2030 planning period is far beyond the Short-Term Action Plan window (2023 – 2027), and AES Indiana will conduct another IRP in 2025 that reevaluates strategies for this period. This future IRP will update assumptions as necessary to account for renewable energy availability and accreditation.

5. Sunk Costs. AES Indiana's analysis reasonably reflects that the undepreciated costs for Petersburg will be recovered through rates regardless of whether the units remain on coal, are retired, or are repowered to natural gas. We find that the net present value analysis provided in the IRP is consistent with the industry standard concerning the treatment of undepreciated costs for the Petersburg Repowering Project.

6. Upstream Emissions. AES Indiana reasonably limited its analysis to only "inside the fence" emissions or emissions directly associated with combustion processes and power production at the plants. If AES Indiana were to include upstream emissions for power production using natural gas, then it would also have to include them for power production using coal, which would also negatively impact the strategy that Ms. Medine prefers by an even greater margin due to EPA constraints that apply only to coal.

7. Capacity Factors. Ms. Medine's assessment of the Project focuses on the energy revenue generated from coal operation versus natural gas operation and does not account for the substantial reduction in fixed O&M costs ($683 million, per Mr. Miller's direct testimony) that result from repowering the units. Pet. Ex. 8 at 39-40. The complete analysis supports the proposed conversion.

8. Parent Company Global Goals. We now turn to Ms. Medine's assertion that "it appears the timing [of the Petersburg Repowering Project] is being driven by AES's [AES Indiana's] parent's [The AES Corporation] strong desire to be off coal as soon as possible." REI Ex. 1, at 7. She contended the Project should be justified based upon a retirement date of 2040 rather than the 20-year depreciable life used by AES Indiana, based on The AES Corporation's 2040 Net Zero plan. Mr. Bigalbal quantified the difference between depreciating over 20 years (as reflected in AES Indiana's analysis) versus 13 years (as proposed by REI) and showed this approach would not change the outcome of the financial analysis. This analysis demonstrates that rejection of the Petersburg Repowering Project is not warranted based on Ms. Medine's contention that any new investment in natural gas generation should be justified based upon a firm retirement date of 2040 due to the AES Corporation's 2040 Net Zero plan.

AES Indiana presented substantial evidence demonstrating the 2022 IRP was conducted using reasonable and defensible assumptions that were stress tested in various ways, including the use of stochastic analyses. The 2024 IRP updates reasonably account for changing market conditions and environmental regulations. The evidence shows the decision to repower Petersburg Units 3 and 4 is reasonable across a range of possible futures. The OUCC, the statutory representative of the public in Commission proceedings, agreed that the Petersburg Repowering Project is reasonable, consistent with the 2022 IRP and updated analyses, and recommended approval of the Repowering Project.

9. PVRR. 170 IAC 4-7-4 requires that an IRP include at least a 20-year future period for predicted or forecasted analysis; AES Indiana's IRP included a 20-year PVRR consistent with this rule. In his discussion of affordability, Mr. Miller presented the 20-year and ten-year PVRR results. Pet. Ex. 7, at 25-26 (Figure 6). Figure 6 shows the Petersburg Conversion remains a reasonable least cost strategy in both the 20- and ten-year PVRR cases, with the ten-year PVRR for the no early retirement and Petersburg conversion being the same. Referring to these analyses, REI witness Medine asserted that "[t]here appears to be no financial benefit given the equivalent NPV for the 10-year period[.]"

Focusing on the ten-year PVRR fails to account for the demonstrated risk that remaining on coal at Petersburg poses to AES Indiana customers. Should CO_2 regulation become more stringent, the evidence shows that the cost to operate Petersburg as a coal resource becomes more expensive and less cost effective compared to operating the units on natural gas. AES Indiana's evidence demonstrates that the PVRR for repowering the units to natural gas is $100 million less than keeping the units on coal over the ten-year period when compliance with GHG NSPS is included in the analysis. In this analysis, the PVRR savings over the 20-year period are much greater. The evidence also shows that there are non-PVRR sustainability benefits of repowering the units to natural gas, including reducing by half the CO_2 per MWh generated, eliminating SO_2 emissions, eliminating coal combustion waste, and greatly reducing particulate matter emissions.

The Commission is mindful that Ind. Code § 8-1-2-0.5 establishes that it is the continuing policy of the state 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. The 20-year planning horizon, which is required by the Commission's IRP rules, better captures the impact of investment on future generations of Indiana citizens than the ten-year period. For all of these reasons, we find and conclude that the PVRR analyses support the Repowering Project.

iii. <u>Public Convenience and Necessity</u>. Ind. Code § 8-1-8.5-5(b)(3) requires that the Commission find that the public convenience and necessity requires or will require the proposed Petersburg Repowering Project. As discussed above, AES Indiana identified a need for this Project. AES Indiana's analyses, as sponsored in particular by Mr. Bigalbal and Mr. Miller, show that the Petersburg Repowering Project represents a reasonable, least-cost option for AES Indiana to utilize in meeting its ongoing obligation to provide adequate and reliable electric service and facilities. AES Indiana considered alternative options using sound load forecasting and resource planning processes. Mr. Miller's PVRR analyses demonstrated that the addition of the Petersburg Repowering Project is consistent with the preferred resource portfolio and the Short-Term Action Plan identified in AES Indiana's 2022 IRP and the 2024 IRP update. The Petersburg Repowering Project is the product of a competitive resource solicitation. The Project will have a positive social and economic impact to the community of Petersburg and Pike County. The Project will provide support for intermittent renewable resources because the units provide firm capacity that is required for a reliable and stable grid. As Mr. Bigalbal testified, the converted units operating on natural gas will be significantly more flexible than a coal plant.

The energy industry and the Commission have long operated under uncertain environmental, regulatory, and political conditions. Because neither the Commission nor the parties are capable of predicting the future, we must make decisions in the face of uncertainty. We do so by logically and reasonably assessing the extent of uncertainty and the possible effects of this uncertainty, avoiding supposition.

The Commission and utilities subject to our jurisdiction use the integrated resource planning process to evaluate how to meet a utility's future electricity requirements. The Commission's rules require a detailed analysis supported by sound facts and assumptions, transparency, stakeholder input and prudent risk assessments. Risk of the future unfolding in a different manner is assessed through economic modeling and analysis of multiple scenarios, portfolios, and futures.

In accordance with 170 IAC 4-7-4(26), AES Indiana's 2022 IRP included a description and analysis of alternative scenarios to the base case scenario, including comparison of the alternative scenarios to the base case scenario. In this proceeding, AES Indiana took the additional step of updating its IRP to determine whether the 2022 IRP preferred resource portfolio and Short-Term Action Plan, which include the Petersburg Repowering Project, remain the reasonable least cost strategy and consistent with the IRP. In addition, when REI asked for analysis regarding the impact of the GHG NSPS, AES Indiana provided it. 170 IAC 4-7-2.5(b) allows utilities to update their IRP analysis.

REI contends there is "plenty of time" to continue to operate the units on coal prior to the January 1, 2030 deadline in the GHG NSPS and that it is imprudent for AES Indiana to proceed with the Petersburg Repowering Project because it could result in stranded costs due to the future environmental regulatory uncertainty. REI argued, in various ways, that the repowering should be delayed or denied because of uncertainty with the GHG NSPS and the Good Neighbor Rule, including speculation that the repowering might eventually be declared unlawful, the rules would be overturned, the repowered unit would be adversely affected by IDEM's development of a state plan, the units might not qualify as "existing EGU," or the Project might be viewed as "reconstruction."

The Commission recognizes that it is common for environmental regulations affecting electric utilities to face legal challenges and revisions. These matters take years to proceed through the appellate process and associated remand proceedings. It is unrealistic to expect that a Commission decision to reject the current Project will allow time for the legal uncertainty to be resolved within the timeframe that resource decisions must be made.

Mr. Bigalbal reviewed the project development and construction timeline and explained that delay would cause the loss of the existing EPC contract and impose other risks. He disputed REI's position that there is "plenty of time" to delay. Substantial evidence shows that a Commission decision to deny the requested CPCN will foreclose the viable Petersburg Repowering Project prudently developed by AES Indiana and presented in this proceeding, and a future conversion project would likely come at an increased cost to ratepayers and risk of untimely completion.

The proposed Petersburg Units 3 and 4 Conversion is relatively inexpensive at less than $300/kW to maintain the existing capacity of over 1,000 MW. By contrast, the estimated cost of a simple cycle gas turbine (which is commonly used as the least cost option for new capacity) is between $700/kW and $1,150/kW, according to Lazard's LCOE+ 2024. The conversion lowers the exposure to future environmental regulations by significantly reducing air emissions, including carbon dioxide, eliminating coal combustion residuals, and reducing the amount of water needed at the facility. The primary cost savings for the conversion from coal to natural gas will result from the fixed O&M cost, which will be reduced by $683 million, and the reduction in CO2 emissions illustrated in Figures 3 and 11 from Mr. Miller's direct testimony, reproduced above.

AES Indiana's IRP analysis effectively "bookended" the range of environmental regulation uncertainty by using a "No Environmental Action" scenario on one end and a "Decarbonized Economy" scenario on the other end and Mr. Miller's additional analysis supplemented this modeling. The extensive analyses support the conclusion that the Petersburg Repowering Project is a reasonable "least cost" choice across a range of possible futures.

We find it significant that, regardless of how the future unfolds with respect to the GHG NSPS or the Good Neighbor Rule, there will be a definite, significant, known, and quantifiable decrease in fixed O&M costs of $683 million as a result of converting the units from coal to natural gas. This fact was not contested by any party. This decrease comes from the removal of the cost to operate coal handling and coal emissions control equipment and is the primary driver behind the cost effectiveness of repowering the units compared to keeping them fueled by coal. These fixed O&M cost reductions will benefit AES Indiana's customers. In other words, AES Indiana proposes to repower the units because the IRP economic modeling supports the conclusion that it is a reasonable, least-cost option. The evidence shows that AES Indiana is not pursuing the repowering as a means to comply with GHG NSPS.

In addition, AES Indiana entered into the EPC Agreement prior to the announcement of the GHG NSPS, thus avoiding any increase in costs or schedule delays related to an increase in EPC Contractor or materials and supplies demand due to the GHG NSPS. Maintaining the Petersburg units on natural gas as a lower-cost, cleaner, reliable, dispatchable capacity resource supports reliability within Indiana and MISO.

Accordingly, the Commission is persuaded that now is the optimal time to repower Petersburg Units 3 and 4 as proposed by AES Indiana.

iv. **<u>Consideration of Alternatives</u>.** As reflected in the above summary of evidence, AES Indiana's 2022 IRP and the testimony of Mr. Miller address each of the items set forth in Ind. Code § 8-1-8.5-4, which we have considered as required by statute. The OUCC recommended approval of AES Indiana's proposed repowering. REI opposes the repowering and seeks to have Petersburg Units 3 and 4 continue to operate on coal. AES Indiana's IRPs have considered alternatives in detail and are described at length above.

REI argued that AES Indiana was required to consider selling Petersburg Units 3 and 4 to a third party, citing the sale of Merom Generating Station as precedent for a private investor to acquire a coal plant that a utility desires to retire. However, REI witness Medine did not demonstrate that such a transaction would be beneficial from a resource planning perspective or otherwise comport with the Five Pillars. A third-party sale is not a required alternative under Ind. Code § 8-1-8.5-4 or otherwise mandated by statute. In addition, the facts of the sale of Merom Generating Station are distinguishable from the circumstances of this case, as its owner, Hoosier Energy, planned to retire the plant.

As stated repeatedly by its witnesses, AES Indiana has no plans to retire Petersburg Units 3 and 4, as it views these units as valuable capacity and energy resources. AES Indiana proposes to repower these units to reduce operating costs and environmental regulatory risk so that the units may further the utility's provision of reliable, affordable, and environmentally sustainable service. Substantial evidence demonstrates that the proposed repowering of Petersburg to natural gas is a long-term, low-cost solution that will help provide resource adequacy for a long period of time. *See, e.g.*, Figures 1, 6, and 9 from Mr. Miller's direct testimony, reproduced above. Substantial evidence also shows that third-party ownership would not be "less risk" for AES Indiana customers.

Consistent with Ind. Code § 8-1-8.5-4, we have considered alternatives to the Repowering Project and find that the evidence demonstrates that the Petersburg Repowering Project is preferable to such alternatives.

v. **<u>GAO 2022-01</u>.** GAO 2022-01 provides guidance on certain regional transmission organization-related information a utility should submit in certain proceedings. AES Indiana compiled the information required by GAO 2022-01 in Pet. Ex. 3, Attachment GAC-1.

vi. **<u>Conclusion on CPCN</u>.** The Commission has indicated in previous CPCN cases that "'least-cost planning' is an essential component of our [CPCN] law." Indianapolis Power & Light Co., Cause No. 44339, at 20 (May 14, 2014) (citations omitted). We have also defined "least-cost planning" as a "'planning approach' which will find the set of options most likely to provide utility services at the lowest cost once appropriate service and reliability levels are determined." Id. The Commission has emphasized that the CPCN statute

> does not require the utility to automatically select the least cost alternative. Nor does the statute require the utility to ignore its obligation to provide reliable service or to disregard its exercise of reasonable judgment as to how best to meet its obligation to serve . . . if an Indiana utility reasonably considers and evaluates the statutorily required options for providing reliable, efficient, and economic service, then the utility should, in recognition that it bears the service obligations of Ind. Code § 8-1-2-4, be given some discretion to exercise its reasonable judgment in selecting the option or options to implement which minimize the cost of providing such service.

Id. (cleaned up).

Based upon the evidence of record, the Commission finds that AES Indiana has shown a need for the requested Petersburg Repowering Project. We further find that AES Indiana's utility-specific proposal, supported by the 2022 IRP (which was corroborated by the 2024 Update presented in this case), is reasonable and should be approved. We also find that AES Indiana's decision to proceed with the Petersburg Repowering Project is a reasonable, least-cost option (saving ratepayers $683 million in fixed O&M costs) to meet AES Indiana's need for capacity. The Petersburg Repowering Project will result in a reliable, less expensive, environmentally sustainable, dispatchable resource to supply the capacity and energy needs of AES Indiana customers. As such, we find that the Petersburg Repowering Project is consistent with AES Indiana's 2022 IRP and the 2024 updated analyses and a CPCN for the Project as described in AES Indiana's testimony is approved.

B. **<u>Clean Energy Project; Accounting and Ratemaking</u>.** Ind. Code § 8-1-8.8-11(a) provides that the Commission "shall encourage clean energy projects by creating . . . financial incentives for clean energy projects, if the projects are found to be just and reasonable[.]" In addition, we "may not approve a financial incentive under this subdivision unless the commission finds that the eligible business has demonstrated that the timely recovery of costs and expenses incurred during the construction and operation of the project . . . is just and reasonable[.]" *Id.* An "eligible business" is an energy utility that "undertakes a project to develop alternative energy sources." Ind. Code § 8-1-8.8-6(3). We have already found that AES Indiana is an "energy utility." Under Ind. Code § 8-1-8.8-2(5), "clean energy projects" include projects to construct or repower a facility described in Ind. Code § 8-1-37-4(a)(21), which are those designed to generate electricity "from natural gas at a facility constructed or repowered in Indiana after July 1, 2011, which displaces electricity generation from an existing coal fired generation facility." Petersburg

Units 3 and 4 fall within the scope of the Ind. Code § 8-1-37-4(a)(21). Therefore, AES Indiana's proposed project is the kind of clean energy project that the Indiana General Assembly has determined should be encouraged and is therefore eligible for the relief provided in Ind. Code § 8-1-8.8-11.

While Ind. Code ch. 8-1-8.8 does not set forth specific factors the Commission should consider in determining whether a clean energy project is just and reasonable, the Commission has considered some of the factors outlined in Ind. Code chs. 8-1-8.5 and 8-1-8.7 in other cases. We have found it appropriate to consider: (1) the cost of the project; (2) the consistency of the project with Petitioner's IRP; (3) the need for the project; and (4) competitive solicitation of the project. *See, e.g.*, *Re Indianapolis Power & Light Co.*, Cause No. 45920, at 18 (Jan. 17, 2024). We have considered all of these factors in preceding sections of this order. Based on the evidence of record, we find that the Petersburg Repowering Project is just and reasonable and approve the Project as a clean energy project. We also approve AES Indiana's proposed cost estimate for the Project.

We now turn to AES Indiana's various accounting and ratemaking requests for the Project. AES Indiana has asked the Commission for the following:

- Approval of and cost recovery for the Project costs and associated agreements;
- Authority to defer depreciation expense, PISCC, and incremental property taxes associated with the Project to a regulatory asset to be recovered in a future base rate case;
- Approval of the decommissioning cost accounting for FGD dewatering and related costs associated with the Petersburg Repowering Project;
- Authority to defer for subsequent recovery through rates net material and supplies inventory that will no longer be used as a result of the Petersburg Repowering Project;
- Authority to defer the project development costs AES Indiana incurs prior to the issuance of a final Commission order in this Cause if the Commission does not approve AES Indiana's proposed Petersburg Repowering Project; and
- Authority to use regulatory asset accounting for the net book value of the Retired Assets associated with the repowering of Petersburg Units 3 and 4 associated with coal operations.

With one exception, explained further below, none of the OUCC's or REI's witnesses opposed any of AES Indiana's accounting or ratemaking proposals.

The OUCC took issue with AES Indiana's proposal to defer project development costs in the event the Commission does not approve the proposed Repowering Project. This issue is moot given our approval of the Project.

Mr. Rogers's testimony establishes that his proposed accounting and ratemaking for depreciation expense, incremental property taxes, and PISCC is reasonable and consistent with the cost recovery afforded to clean energy projects under Ind. Code § 8-1-8.8-11. While timely cost recovery is often sought in similar cases, Mr. Rogers explained that the deferred cost approach he presented in this case aligns well with AES Indiana's expected filing of its next basic rate case. He testified that AES Indiana's proposal provides AES Indiana a reasonable opportunity to earn a return on its investment and to recover the investment through rates over time, consistent with the statutory directive in Ind. Code § 8-1-8.8-11 that the Commission encourage clean energy projects with financial incentives. We conclude that this accounting treatment is consistent with Ind. Code § 8-1-2-10(b) and the legislature's Chapter 8.8 directive to the Commission to encourage repowering projects such as the Petersburg Repowering Project through the use of financial incentives and therefore approve this proposal.

We also approve AES Indiana's proposal to use decommissioning cost accounting treatment for FGD dewatering and related costs. The evidence establishes that decommissioning accounting will reasonably allow AES Indiana to recover future decommissioning costs through recovery of depreciation expense over the life of the assets. These costs are necessarily incurred and are not otherwise reflected in AES Indiana's basic rates.

We also approve AES Indiana's proposed accounting and ratemaking for net material and supplies inventory that will no longer be used as a result of the Petersburg Repowering Project, including the deferral of these costs for subsequent recovery through rates. The evidence shows that AES Indiana's proposal is reasonable because these material and supply costs were prudently incurred for use in the provision of retail service in connection with the operation of the Petersburg Units on coal and the return of such inventory costs is not otherwise reflected in AES Indiana's base rates. Further, the Commission has long allowed recovery through the ratemaking process of the cost associated with investments that were once "used and useful." Such treatment will avoid penalizing AES Indiana for making the economic decision to convert Units 3 and 4 and is consistent with Chapter 8.8's provisions regarding financial incentives and with Ind. Code § 8-1-2-10(b).

In addition, the Commission approves and authorizes AES Indiana's proposed accounting and ratemaking, including the use of regulatory asset accounting, for the net book value of the Retired Assets associated with the repowering of Petersburg Units 3 and 4. The evidence establishes that AES Indiana's proposed treatment will allow the regulatory assets to continue to reduce and will also provide assurance of recovery of such remaining net plant balance through AES Indiana's retail rates. We find this treatment to be reasonable. The Retired Assets have been devoted to and used and useful in the provision of service to AES Indiana's retail customers for decades. Upon retirement, the Retired Assets will not be fully depreciated. If this treatment were not authorized, AES Indiana would be penalized for making the economic decision to convert the units. We also find that this treatment is consistent with Chapter 8.8 and Ind. Code § 8-1-2-10(b).

For the foregoing reasons, we find that AES Indiana's proposed accounting and ratemaking requests are reasonable and are therefore approved.

C. Ind. Code §§ 8-1-2-0.5 and -0.6. Through Ind. Code § 8-1-2-0.5, the Indiana General Assembly has declared that it is the state's continuing policy 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. In Ind. Code § 8-1-2-0.6, the Indiana General Assembly declared 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 Five Pillars of electric utility service (originally outlined in the Task Force report): reliability, affordability, resiliency, stability, and environmental sustainability.

As discussed by AES Indiana's witnesses, the objectives and metrics AES Indiana used during the IRP process to determine its Preferred Portfolio were tightly integrated with the Five Pillars of reliability, affordability, resiliency, stability, and environmental sustainability. Through the IRP process and the analyses performed for this CPCN proceeding, AES Indiana has demonstrated that the Petersburg Repowering Project reasonably considers and balances the Five Pillars. The proposed repowering minimizes the cost of providing service and reasonably mitigates risk as discussed in AES Indiana's direct and rebuttal testimony.

i. Reliability, Resiliency, and Stability. The record indicates that Petersburg Units 3 and 4 have historically been reliable, resilient, and capable of providing grid stability, and the conversion of the units will maintain these attributes into the future. The record also shows the Petersburg Repowering Project supports the ability of the units to reliably supply the capacity and energy requirements of AES Indiana customers with nearly the same capacity, dispatchable near or above 90% accreditation over all four MISO seasons. Large rotating steam turbine-generators provide frequency and voltage support to the grid, which in turn provides stability as load conditions change and disturbances occur. The conversion of Units 3 and 4 will maintain these attributes into the future. A reliability analysis performed by Quanta concluded that the repowered units will be as reliable as continuing to operate the units on coal, and more reliable than replacing those units with wind, solar, and storage. As stated by Mr. Miller, the natural gas conversion of the Units provides excellent support for intermittent renewable resources because the Units provide the firm capacity that is required for a reliable and stable grid.

Allowing AES Indiana to move forward with the Petersburg Repowering Project supports AES Indiana's ability to provide a reliable and resilient system and deliver a stable source of electricity, which is important to its customers and to Indiana's economy. Although REI raised the issue of natural gas supply and transportation risk during extreme events, we found above that AES Indiana has prudently managed that risk through a primary firm transportation contract with MGT, pipeline diversity, and region diversity.

ii. Affordability. The evidence of record shows that the Petersburg Repowering Project is the least-cost option for AES Indiana and its customers across various future scenarios. The evidence also shows that AES Indiana has taken steps to safeguard costs in the negotiation of an EPC Agreement. AES Indiana reasonably demonstrated that the Petersburg Repowering Project has the lowest PVRR of all the candidate portfolios compared to keeping the units on coal. Mr. Rogers testified that the specific accounting and ratemaking proposals made with respect to the Petersburg Repowering Project reasonably consider affordability and that the Petersburg Repowering Project will result in electric utility service that is competitive across all customer classes.

OUCC witness Latham testified that the OUCC did not have concerns about the Project's affordability.

REI argued that AES Indiana's PVRR analysis is insufficient to assess affordability, AES Indiana has not analyzed the rate impact on each customer class. The evidence of record showed that these assertions were incorrect.

In addition, the record includes the 20-year PVRR for the Project and alternatives under the 2022 IRP and the 2024 Update. While it is the province of the Commission to decide what AES Indiana's actual future rates will be, the annual revenue requirements displayed in these figures are a general proxy for customer rate impact by year over the planning period. In his direct testimony, Mr. Rogers estimated the year one rate impact on all customer classes, not just the residential class; REI's contention otherwise was incorrect. Based on the evidence of record, the Commission finds that AES Indiana's PVRR analyses and rate impact calculation demonstrates that affordability has reasonably been considered.

iii. Environmental Sustainability. The environmental sustainability pillar considers the impact of environmental regulations on the cost of providing electric utility service and demand from consumers for environmentally sustainable sources of electric generation. The evidence shows that the Project will produce environmental benefits, such as lower air emissions and elimination of future production of coal combustion residual products. Further, the record shows the IRP reflects stakeholder input regarding sustainability.

The Commission has considered the Five Pillars enumerated in Ind. Code § 8-1-2-0.6 in reaching its decision in this proceeding. The Commission finds the proposed Repowering Project is consistent with the legislative directives.

D. Conclusion. AES Indiana has an ongoing need for the capacity provided by Petersburg Units 3 and 4. The Petersburg Repowering Project proposed in this proceeding is the result of a robust IRP and competitive procurement process and represents a reasonable, least-cost option for AES Indiana. The repowering is expected to result in total savings for ratepayers of between $281 million and $437 million on a PVRR basis due to reduced fixed and variable O&M costs and emission expenditures offset by the modeled cost to attain such reductions. The converted units will be utilized by AES Indiana to meet its ongoing obligation to provide adequate and reliable service and facilities consistent with Indiana energy policy, as articulated in Ind. Code §§ 8-1-2-0.5 and -0.6, Ind. Code ch. 8-1-8.5, and Ind. Code § 8-1-8.8-11. We find that the evidence of record in this proceeding supports approval of the Petersburg Repowering Project and cost recovery as proposed by AES Indiana.

The Project will provide needed capacity, support reliability, and provide environmental benefits, while reasonably balancing affordability of service. We find and conclude that the CPCN should be issued for the Project. We also approve the Project as a clean energy project. Finally, AES Indiana's proposed accounting and ratemaking treatment for the Project is also approved.

10. Petition to Reopen Proceeding. On October 10, 2024, REI filed a Verified Petition to Reopen Proceeding for the Purpose of Taking Additional Evidence ("Petition to Reopen") pursuant to 170 IAC 1-1.1-22(a). In the Petition to Reopen, REI argues that an AES Indiana All-Source RFP issued on September 27, 2024 indicates that AES Indiana's energy and capacity needs have increased since the conclusion of the evidentiary hearing and argues that these are changes in material fact that justify reopening of the record to receive additional evidence under 170 IAC 1-1.1-22(a).

AES Indiana filed a response opposing the Petition to Reopen on October 15, 2024 ("Response"), arguing, among other things, that REI has already had ample opportunity to present its evidence and arguments in this matter, including its arguments regarding load growth, integrated resource planning, consideration of resource options, and "the idea that we have 'plenty of time' to delay the proposed project." Response at 3. AES Indiana also notes that it should be no surprise that it issued an All-Source RFP on September 27, 2024, given that it is required to file its next IRP on or before November 1, 2025. "The fact that [AES Indiana] would be commencing work on its next IRP by issuing an All-Source Request for Proposals . . . is hardly surprising and reasonably could have been foreseen." *Id.* REI filed a reply in support of the Petition to Reopen ("Reply") on October 23, 2024, reiterating the same arguments made in the initial Petition to Reopen.

After reviewing the Petition to Reopen, AES Indiana's Response, and REI's Reply, we find that REI's Petition to Reopen the record is completely unfounded. AES Indiana, in its attempt to search for insight and options in an upcoming IRP through an RFP, outside this docket, is precisely why there is an iterative IRP process of short-term and long-term planning. It is not a material change in fact that justifies reopening the record. Thus, the Petition to Reopen is denied.

11. <u>Confidential Information</u>. On March 11, 2024 and June 26, 2024, AES Indiana filed motions seeking a determination that designated confidential information involved in this proceeding be exempt from public disclosure under Ind. Code § 8-1-2-29 and Ind. Code ch. 5-14-3. These requests were supported by affidavits showing certain documents to be admitted into evidence contained trade secret information within the scope of Ind. Code § 5-14-3-4(a)(4) and Ind. Code § 24-2-3-2. On March 26, 2024, and July 10, 2024, respectively, the Presiding Officers issued docket entries finding such information confidential on a preliminary basis. Subsequent to our docket entries, AES Indiana, the OUCC, and REI submitted designated confidential information.

After reviewing the designated confidential information, we find all such information qualifies as confidential trade secret information pursuant to Ind. Code § 5-14-3-4 and Ind. Code § 24-2-3-2. This information has independent economic value from not being generally known or readily ascertainable by proper means. AES Indiana takes reasonable steps to maintain the secrecy of the information, and disclosure of such information would cause harm to AES Indiana. Therefore, we find that this information should be exempted from the public access requirements contained in Ind. Code ch. 5-14-3 and Ind. Code § 8-1-2-29 and held confidential and protected from public disclosure by this Commission.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION that:

1. AES Indiana is issued a certificate of public convenience and necessity for AES Indiana's Petersburg Repowering Project. This Order constitutes the certificate.

2. The EPC Agreement is approved.

3. AES Indiana's estimated cost of the Petersburg Repowering Project as set forth in Petitioner's Exhibit No. 1 is approved.

4. The Petersburg Repowering Project, including the associated agreements, is a clean energy project under Ind. Code § 8-1-8.8-2, and is just and reasonable under Ind. Code § 8-1-8.8-11.

5. AES Indiana's proposed accounting and ratemaking are approved.

6. AES Indiana is authorized to defer depreciation expense, PISCC, and incremental property taxes associated with the Project to a regulatory asset to be recovered in a future base rate case as proposed by Mr. Rogers.

7. AES Indiana is authorized to use decommissioning cost accounting for FGD dewatering and related costs associated with the Petersburg Repowering Project as proposed by Mr. Rogers.

8. AES Indiana is authorized to defer for subsequent recovery through rates net material and supplies inventory that will no longer be used as a result of the Petersburg Repowering Project as proposed by Mr. Rogers.

9. AES Indiana is authorized to use regulatory asset accounting for the net book value of the Retired Assets associated with the repowering of Petersburg Units 3 and 4 as supported by AES witness Mehringer. AES Indiana is granted accounting authority to implement the amortization of the regulatory assets and include the unamortized balance of the regulatory assets in rate base and continue to amortize such assets through retail rates as described by AES Indiana witness Mehringer.

10. The information filed in this Cause pursuant to the motion for protection and nondisclosure of confidential and proprietary information is deemed confidential pursuant to Ind. Code §§ 5-14-3-4 and 8-1-2-29, is exempt from public access and disclosure by Indiana law, and shall be held confidential and protected from public access and disclosure by the Commission.

11. REI's Petition to Reopen is denied.

12. This Order shall be effective on and after the date of its approval.

HUSTON, BENNETT, FREEMAN, VELETA, AND ZIEGNER CONCUR:

APPROVED: **NOV 06 2024**

I hereby certify that the above is a true and correct copy of the Order as approved.

Dana Kosco Digitally signed by Dana Kosco Date: 2024.11.06 10:15:54 -05'00'

Dana Kosco
Secretary of the Commission