ADVANCED ENERGY UNITED
COMMENTS ON THE
AES INDIANA 2025 INTEGRATED RESOURCE PLAN

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Introduction:

Advanced Energy United ("United") respectfully submits these comments in response to AES Indiana's ("AES" or "Company") 2025 Integrated Resource Plan ("IRP") submitted to the Indiana Utility Regulatory Commission ("Commission") on October 31, 2025. United appreciates the effort that AES and other stakeholders have put into developing the 2025 IRP and emphasizes the importance of continuing to forecast and plan for Indiana's energy needs in the future. Indiana's utilities are at a critical juncture in planning for the State's future, facing a growing need to temper rising energy costs and a potential for exponentially higher load growth driven by new large load customers. United highlights that there are proven and readily available advanced energy technologies that can help address both of these concerns currently plaguing Indiana Utilities. By facilitating the deployment of advanced energy technologies, AES would be able to satisfy its obligation to cost effectively, reliably, and sustainably serve ratepayers and meet Hoosier's energy needs into the future.

United is the only national business association representing leaders in the advanced energy industry. Members include front-of-meter and behind-the-meter ("BTM") renewable energy and battery storage manufacturers and developers, electric vehicle ("EV") and EV charging equipment suppliers, providers of energy efficiency ("EE"), demand response ("DR"), and virtual power plants ("VPP"), as well as larger users of energy wanting to ensure that clean energy is available on the grid to facilitate corporate sustainability goals. United members work to enhance the United States' competitiveness and economic growth through an efficient, high-performing energy system that is clean, secure, affordable, and reliable. United works with decision-makers at the state and national level as well as regulators of energy markets to achieve this goal. In Indiana, United aims to drive the development of advanced energy by identifying growth opportunities, removing policy barriers, encouraging market-based policies, establishing partnerships, and serving as the voice of innovative companies in the advanced energy sector.

Although the Commission is unable to make direct changes to AES's 2025 IRP, United would like to identify some concerns with AES's IRP in the hope that the Director's Report in response to the IRP will encourage AES to improve its processes for developing future IRPs. The five areas that United addresses in these comments are as follows: 1) DR and EE Program Considerations, 2) Petersburg Units 3 and 4 Retirement and Future Replacement, 3) Lakefield Wind Park PPA Future Considerations, 4) ATT and Grid-Enhancing Technology Future Considerations, and 5) Large Load Considerations and Supply Flexibility . Each of these concerns is discussed in more detail within the "Key Considerations and Recommendations" section of these comments. Silence regarding other aspects of AES's IRP should not be taken as support or acquiescence.

Background:

Indiana defines an IRP as "a utility's assessment of a variety of demand-side and supply-side resources to cost effectively meet customer electricity service needs".[1] As

[1] *See* Indiana Administrative Code 170 17.1-2-11

established in Indiana Administrative Code ("IAC") 170 4-7-2, each utility that owns generating facilities is required to submit an IRP to the Commission every three years.[2] AES has previously submitted IRPs to the Commission in 2019 and 2022 respectively. As mentioned in the Final Directors Report for AES's 2022 IRP, the purpose of an IRP is to "develop a long-term power system resource plan that will guide investments to provide safe and reliable electric power at the lowest delivered cost reasonably possible."[3] Furthermore, it is critical for IRPs to be flexible, as well as support the unprecedented pace of change currently occurring in the production, delivery, and use of electricity.

Following the submission of an IRP by a utility, the Commission does not have the authority to make direct changes to an IRP, however, as established in Indiana Code 8-1-8.5-3.3, "the director of the commission's research, policy, and planning division shall evaluate and comment in the commission's final director's report for the plan as to whether the electric utility's preferred resource portfolio takes into account the attributes of electric utility service including: 1) reliability; 2) affordability; 3) resiliency; 4) stability; and 5) environmental sustainability".[4] The Director's Report is a critical document, as it takes into account outside stakeholders' comments and serves as the main conduit for influencing and guiding utilities' future IRP proposals. The Final Director's Report for AES's 2022 IRP and subsequent stakeholder comments has therefore served as an informative resource when understanding AES's 2025 IRP.

In preparation for the 2025 IRP filing, AES engaged with stakeholders to receive feedback on the development of the IRP and hosted four public stakeholder meetings between January 2025 and October 2025 to promote transparency and encourage feedback on the IRP process. In addition to the public advisory meetings, AES also hosted four technical meetings for stakeholders that signed a Non-Disclosure Agreement ("NDA") and were interested in the specific EnCompass modeling development and technical details of the IRP process. AES also hosted a total of sixteen meetings on demand response and energy efficiency programs for stakeholders that signed an NDA. AES accepted written thoughts and questions as well and ultimately submitted the IRP to the Commission on October 31, 2025.

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[2] *See* Indiana Administrative Code 170 4-7-2
[3] *See* Final Director's Report for AES Indiana's 2022 Integrated Resource Plan, August 26, 2024
[4] *See* Indiana Administrative Code 8-1-8.5-3.3

AES's 2025 IRP – Overview:

AES's 2025 IRP indicates that the Company is susceptible to various market-wide transformations that are occurring or expected to occur in the near future, and the Company is proposing various actions to mitigate the impacts of these changes and remain flexible in the face of volatility. AES forecasts its energy load and peak demand to be relatively flat in the future with energy load experiencing an average annual growth rate of 0.7% and peak demand experiencing an average annual growth rate of 0.8% over the IRP planning horizon ending in 2045 with future demand-side management ("DSM") impacts removed from consideration.[5] Furthermore, residential customer growth is expected to increase at an average annual rate of 1.0% through 2045 with commercial and industrial customer growth expected to increase at an average annual rate of 0.3% through 2045.[6] A key factor to consider in AES's forecasted modest peak demand and load growth is the fact that AES Indiana does not currently have an energy services agreement with a large load customer, however, from large load customers expressing interest in developing data center campuses within AES's service territory.[7] Given this information, AES's peak demand and load growth remain volatile and uncertain depending on whether or not large load customers will develop within AES's service territory.

In addition to the uncertain impacts due to large load customers, AES is also experiencing changes in its generation resource composition with the Company expecting its Petersburg coal generation plant units 3 and 4 to retire and be repowered to natural gas in 2026.[8] Peterburg units 3 and 4 currently combine for a nameplate capacity of 1,040 MW and when repowered to natural gas will have a combined nameplate capacity of 1,052 MW as indicated in AES's 2022 IRP.[9] AES also utilizes various wind, solar, and battery resources to meet electricity demand either through power purchase agreements ("PPAs") or directly under contract via its Rate REP structure. These resources are discussed in greater detail in the sections below.

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[5] *See* AES Indiana's '2025 Integrated Resource Plan Volume I' submitted to the Indiana Utility Regulatory Commission on October 31, 2025 at Pg. 48

[6] *Ibid.*

[7] *Id.* At Pgs. 14 and 71

[8] *See* AES Indiana's '2025 Integrated Resource Plan Volume I' submitted to the Indiana Utility Regulatory Commission on October 31, 2025 at Pg. 75

[9] *Ibid.*

Due to the various forms of uncertainty that AES is experiencing, the 2025 IRP presents two preferred resource portfolios to guide resource acquisition through 2032: one to address current customer load growth, and one to support large load customers if they develop within AES's service territory.[10] To accomplish developing two preferred resource portfolios, AES crafted four different IRP scenarios along with four different levels of large load integration to yield sixteen unique sets of resource portfolios that were each run four times through the EnCompass model resulting in 64 different model runs.[11] The four different IRP scenarios are as follows: 1) Reference Case representing current market conditions, 2) Gas Infrastructure Challenges where gas prices are high, 3) High Regulatory: Environmental indicating a return to tax credits for renewables and storage and the re-implementation of Clean Air Act 111(b), and 4) Stable Markets Scenario where resource costs are in-line with historical trends and commodity prices are low.[12] The four different levels of large load integration are as follows: 1) No Data Center Load representing 0 MW of additions, 2) Low Data Center Load representing 307 MW of additions by 2032, 3) Mid Data Center Load representing 1,591 MW of additions by 2032.[13]

The two preferred portfolios that AES chose for its 2025 IRP are: 1) Reference Case with no data center load, and 2) Reference Case with mid data center load. The Reference Case with no data center load preferred portfolio will utilize 152 MW of firm demand response, 133 MW of energy efficiency, and 40 MW of storage resources by 2032. The Reference Case with mid data center load will continue to utilize 152 MW of firm demand response and 133 MW of energy efficiency, however, this preferred portfolio will also install 820 MW of battery storage and 700 MW of combined cycle natural gas resources by 2032.[14] **Figure 9-132** below showcases the installed capacity of the resource additions that will be added in both preferred portfolio options through 2032.

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[10] *Id.* At Pg. 14
[11] *Id.* At Pgs. 16 and 17
[12] *Ibid.*
[13] *Ibid.*
[14] *See* AES Indiana's '2025 Integrated Resource Plan Volume I' submitted to the Indiana Utility Regulatory Commission on October 31, 2025 at Pg. 258

Figure 9-132: Reference Case Portfolio Additions: Installed Capacity (MW)

		2027	2028	2029	2030	2031	2032
Demand Response	No Data Center Load	44	61	107	130	144	152
	Mid DC Load	44	61	105	124	133	138
Energy Efficiency	No Data Center Load	34	57	78	98	116	133
	Mid DC Load	34	57	78	98	116	133
Battery Storage	No Data Center Load		20	20	20	20	40
	Mid DC Load		200	360	580	860	860
Gas CCGT	No Data Center Load						
	Mid DC Load						700
Gas CT	No Data Center Load						
	Mid DC Load						
Gas Reciprocating Engines	No Data Center Load						
	Mid DC Load						
Solar	No Data Center Load						
	Mid DC Load						
Wind	No Data Center Load						
	Mid DC Load						
Summer Capacity Market Purchases/(Sales)	No Data Center Load	2	27	(10)	(15)	(17)	(33)
	Mid DC Load	2	34	49	48	(0)	(50)
Winter Capacity Market Purchases/(Sales)	No Data Center Load	22	41	31	28	32	44
	Mid DC Load	23	(43)	22	49	48	(50)

To further study the four different IRP scenarios and the four different large load integration assumptions, AES also conducted seven alternative scenarios or sensitivities intended to capture the impacts of different circumstances that could occur and impact AES's resource planning. These alternative scenarios or sensitivities were crafted by either AES internally or proposed by outside stakeholders and are as follows: 1) Data center transmission investment, 2) Small Modular Reactor Breakeven Analysis, 3) Enhanced Realistic Achievable Potential Energy Efficiency Bundles, 4) Tax Credit reinstatement, 5) Data Center load factor differences, 6) Data Center early exit, and 7) stable markets scenario.[15] Each of these scenarios and sensitivities yielded interesting results, however, AES ultimately selected the aforementioned preferred portfolios based on the established reference case.

To evaluate the various resource portfolios, AES developed specific performance metrics to measure and compare the successfulness of each portfolio in meeting AES needs, ultimately presenting these metrics as a "scorecard". The performance metrics were specifically chosen to align with the Five Pillars of Indiana energy policy as well as

[15] *See* AES Indiana's '2025 Integrated Resource Plan Volume I' submitted to the Indiana Utility Regulatory Commission on October 31, 2025 at Pg. 147

the specific Commission-established IRP objectives. The performance metric categories are: 1) Affordability, 2) Reliability, Resiliency, and Stability, 3) Risk & Opportunity, and 4) Environmental. An example of a metric utilized by AES is that the 10-year levelized supply cost was used to evaluate the affordability of various scenarios.[16] AES thus calculated the performance metric for each of the sixteen different scenarios which resulted in the following scorecard results as shown below in **Figure 0-4**.

Figure 0-4: Scorecard Results

		AFFORDABILITY				RELIABILITY, RESILIENCY, AND STABILITY					RISK & OPPORTUNITY				ENVIRONMENTAL	
Data Center Case	Portfolio	10-Year Levelized Supply Cost	25-Year Supply Cost	10-Year PVRR	25-Year PVRR	Market Purchases + Sales	25-yr energy purchases, % of load	25-yr energy sales, % of load	Dispatchable Capacity, Percent of Peak (2035)	Dispatchable FIRM Capacity, Percent of Peak (2035)	Opportunity (Mean - P5)	Risk (P95-Mean)	Enviro. Scenario Risk	Avg. % Difference from Optimal	Total CO2 Emissions (25-yr)	Carbon Intensity (25-yr avg.)
	Units →	$2026/MWh	$2026/MWh	2026$MM	2026$MM	%	%	%	%	%	%	%	2026$MM	%	Million Tons	lb/MWh
No Data Center Load	Reference Case	$149	$161	$5,126	$10,092	26%	16%	10%	111%	90%	17%	18%	$234	0%	147	772
	Gas Infrastructure Challenges	$149	$162	$5,154	$10,161	21%	13%	8%	111%	90%	17%	18%	$237	4%	146	766
	High Regulatory: Environmental	$156	$188	$5,906	$15,455	25%	11%	14%	111%	91%	7%	9%	$0	52%	99	523
	Stable Markets Scenario	$149	$161	$5,126	$10,070	27%	18%	9%	111%	90%	17%	19%	$57	0%	153	805
Low Data Center	Reference Case	$144	$151	$5,985	$12,654	23%	15%	8%	121%	99%	14%	18%	$239	3%	183	806
	Gas Infrastructure Challenges	$148	$153	$6,400	$13,047	21%	11%	10%	118%	98%	12%	15%	$970	7%	177	777
	High Regulatory: Environmental	$153	$180	$7,099	$19,827	26%	12%	14%	117%	96%	6%	8%	$0	53%	111	486
	Stable Markets Scenario	$145	$151	$6,020	$12,699	23%	15%	8%	119%	97%	15%	18%	$196	1%	194	854
Mid Data Center	Reference Case	$138	$139	$7,971	$18,187	17%	12%	5%	122%	102%	11%	16%	$658	3%	247	812
	Gas Infrastructure Challenges	$139	$140	$8,220	$18,499	17%	10%	7%	117%	99%	11%	15%	$1,217	6%	232	763
	High Regulatory: Environmental	$151	$174	$10,236	$30,040	21%	10%	11%	118%	98%	4%	6%	$0	60%	117	384
	Stable Markets Scenario	$138	$139	$7,967	$18,266	17%	12%	4%	121%	100%	12%	18%	$209	2%	278	914
High Data Center	Reference Case	$134	$132	$9,975	$23,754	15%	10%	5%	118%	102%	11%	15%	$1,434	3%	295	779
	Gas Infrastructure Challenges	$135	$133	$10,132	$24,032	14%	8%	7%	125%	109%	10%	14%	$1,851	5%	292	770
	High Regulatory: Environmental	$145	$164	$12,246	$37,871	18%	10%	8%	120%	99%	4%	7%	$0	52%	149	394
	Stable Markets Scenario	$134	$133	$9,959	$23,990	14%	10%	4%	133%	112%	11%	16%	$590	2%	333	879

The development of AES's Preferred Portfolios is the ultimate goal of the 2025 IRP as the Preferred Portfolios identify the amount, timing, and type of resources required to supply energy in both the near-term (2025-2030) and long-term (2031-2044). AES states that its 2025 IRP was precedent-breaking in the selection of two preferred portfolios, however, this was the optimal outcome because it allows AES to prepare to meet its service requirements under different outcomes and reflects that if new large loads were to be located within the AES service territory AES would have to install

[16] See AES Indiana's '2025 Integrated Resource Plan Volume I' submitted to the Indiana Utility Regulatory Commission on October 31, 2025 at Pg. 160

additional resources, however, if loads go elsewhere, then AES would not have to install additional resources.[17]

Since AES's 2022 IRP, the Company has made various changes to its IRP methodology, incorporating feedback from both the Commission and stakeholders following the 2022 IRP. These changes include: 1) Updated load forecast calculations for normal weather as well as solar and electric vehicles, with normal weather using over 50 years of data to explicitly capture climate change effects, 2) Improved DSM bundling methodology for DR, EE, and Time-of-Use rates as a result of stakeholder collaboration, and 3) Enhanced IRP scorecard metrics for portfolio evaluation using levelized supply costs as an affordability metric and additional reliability metrics on dispatchable capacity.[18] The aforementioned incorporated changes allowed AES to develop its two preferred portfolios and subsequent short-term action plan especially in the reliance of improving DR and EE resource bundles.

For immediate next steps, AES developed a short-term action plan based on the results of the two preferred portfolios. The short-term action plan states that AES will add 130 MW of firm capacity in DR by 2030 and 150 MW by 2032 whether or not new large loads come online which could equate to 200 MW of installed capacity in summer of 2032. AES will also add 100 MW of energy efficiency by 2030 and 130 MW by 2032 whether or not new large loads come online. Furthermore, AES plans to add 40 MW of battery storage by 2032, however, if a new large load comes online it will significantly increase this capacity to consider adding 860 MW of battery storage by 2032. Finally, if a new large load comes online, AES will consider adding 700 MW of a combined cycle natural gas generating station by 2032. [19] AES, as part of its short-term action plan, has also submitted various transmission system projects to bolster the resource additions associated with the 2025 IRP preferred portfolio.[20] All of these topics are discussed in further detail in the sections below, and AES states that the 2025 IRP marks a significant shift for AES Indiana and it remains committed to ongoing collaboration with stakeholders to ensure it continues to responsibly meet the evolving electricity needs of Central Indiana.

[17] *Id.* At Pg. 258
[18] *See* AES Indiana's '2025 Integrated Resource Plan Volume I' submitted to the Indiana Utility Regulatory Commission on October 31, 2025 at Pg. 24
[19] *Id.* At Pg. 262
[20] *Id.* At Pg. 266

Key Considerations and Recommendations:

United has reviewed AES's 2025 IRP and appreciates the work that AES invested in the process. Nevertheless, United has identified areas of concern within the 2025 IRP and provides the following general considerations on the IRP as a whole, as well as specific recommendations and analysis on the individual topics mentioned below.

1. *Demand-Side Management: Demand Response and Energy Efficiency Program Considerations*

   As discussed in the previous sections, AES's preferred portfolio includes adding 150 MW of firm capacity in DR and 130 MW of EE by 2032 regardless of whether new large loads come online within AES's service territory. This level of DR and EE is substantial and indicates that DSM programs comprise a significant portion of AES's resource additions for the 2025 IRP. The DSM resources that AES relies upon can be broken down into two main categories: residential programs and commercial programs. AES's residential DSM programs consist of the following: Efficient Products, Home Energy Reports, Income Qualified Weatherization, Multifamily Direct Install, and School Education. The total annual energy savings of these residential programs in Ex Post Net kilowatt-hours (kWh) for 2024 was 51,664,027 kWh. AES's commercial DSM programs consist of the following: Custom Incentives, Prescriptive Rebates, and Small Business Direct Install. The total annual energy savings of these commercial programs in Ex Post Net kWh for 2024 was 96,413,734 kWh.[21] AES also has additional DSM programs such as the Load Curtailment/Interruptible Demand Response Program which constitutes 9 MW of annual capacity and the EV Charging Rewards Program which was approved in 2025 under IURC Cause No. 45843 and expects to see initial results of the program in 2028.[22] To incorporate DSM into the 2025 IRP, AES developed a Market Potential Study ("MPS") which calculates the reasonably achievable level of DSM in AES's service territory by estimating customer adoption rates for a comprehensive list of DSM measures.[23] The MPS allows for DSM to be modeled on a consistent and comparable basis with supply-side resources, and yields Realistically Achievable Potential (RAP) results for DSM that can be categorized into selectable "bundles" that can be

[21] *See* AES Indiana's '2025 Integrated Resource Plan Volume I' submitted to the Indiana Utility Regulatory Commission on October 31, 2025 at Pg. 90
[22] *Id.* At Pgs. 93-94
[23] *Id.* At Pg. 95

selected in the 2025 IRP as supply resources.[24] Levels of demand potential associated with the RAP scenario from the MPS were provided as inputs to EnCompass. The 2025 IRP ultimately selected a significant amount of DSM resources (as indicated above) and in order to hit the targets calculated in the RAP and MPS, AES plans to seek Commission approval to deliver DSM programs in 2027 through 2029 at levels consistent with the 2025 IRP. If no new large loads come online, the following DR bundles will be selected as supply resources: DR Thermostat, DR Load Curtailment, Residential Behavioral DR, and DR Time-of-Use Rate. If data centers come online, AES will consider adding a DR battery bundle and a DR Peak Time Rewards bundle as well. EE was bundled by sector and by time period for selection in the EnCompass model with "Vintage 1" being selected and encompassing 2027-2029. EE bundles selected will remain the same regardless of if new large loads come online or not. **Table 10-2, Table 10-3**, **Table 10-4** and **Table 10-5** highlight the DR and EE targets that AES seeks to achieve in-line with the 2025 IRP.

Figure 10-2: Cumulative Energy Efficiency Targets - *Vintage 1 (2027-2029)*

Vintage 1 Bundles	Cumulative MWh (2027 – 2029)	Summer Capacity (2029, MW)
C&I	418,275	35
Res Tier1 (Res Behavior)	219,603	16
IQW[64]	57,655	6
IQ HEAR[65]	12,927	-
Total	708,460	57

Figure 10-3: Estimated Energy Efficiency Targets[66]

Vintage 1 - Incremental Net Savings (MWh)	2027	2028	2029
C&I V1	85,189	73,932	66,161
Res BEH Tier1 V1	50,467	51,972	52,901
IQW V1	11,047	9,513	9,075
Total Estimated Energy Efficiency Targets	146,704	135,418	128,137

Figure 10-4: Estimated Demand Response Targets[69]

Summer Installed Capacity (MW)	2027	2028	2029
DLC Thermostat (Free Thermostat + BYOT)	53.8	56.1	59.0
C&I Load Curtailment	9.4	30.5	63.5
Res Behavioral DR	-	-	25.8
TOU Rate	-	-	2.0
Total	**63.2**	**86.5**	**150.4**
Summer Firm Capacity (MW)	**2027**	**2028**	**2029**
DLC Thermostat (Free Thermostat + BYOT)	37.6	39.3	41.3
C&I Load Curtailment	6.6	21.3	44.5
Res Behavioral DR	-	-	18.1
TOU Rate	-	-	1.4
Total	**44.2**	**60.6**	**105.3**

[24] *Ibid.*

Figure 10-5: Additional Estimated Demand Response for Consideration[70]

Summer Installed Capacity (MW)	2027	2028	2029
Battery Storage	0.1	0.4	1.0
Res Peak Time Rebate	0.0	0.0	2.1
Total	**0.1**	**0.4**	**3.0**

Summer Firm Capacity (MW)	2027	2028	2029
Battery Storage	0.1	0.2	0.7
Res Peak Time Rebate	-	-	1.4
Total	**0.1**	**0.2**	**2.1**

Ultimately, in the absence of new large loads, AES's 2025 IRP showcases that shortfalls can be addressed through demand-side strategies such as energy efficiency, demand response, and battery storage.[25] United strongly supports AES's strategy to meet any capacity shortfalls with demand-side strategies and applauds AES's selection of these resources in the 2025 IRP. United additionally emphasizes that demand-side strategies can address resource shortfalls even if large load customers come online within AES's service territory. DSM being utilized to address large load customer concerns is discussed in more detail in subsequent sections, however, United supports AES's interest in "exploring how large loads might actively participate in demand-side programs" which could "help reduce peak demand, defer infrastructure upgrades, and improve overall system flexibility". [26]

2. *Petersburg Units 3 and 4 Retirement and Future Replacement*

AES operates the Peterburg coal-fired generating station in Pike County, Indiana which consists of four different power units. Units 1 and 2 were retired in 2021 and 2023 respectively as a result of the 2019 IRP and Units 3 and 4 are scheduled to be retired and repowered to natural gas generating stations in 2026 as a result of AES's 2022 IRP.[27] Petersburg Units 3 and 4 each operate at 520 MW of capacity (collectively 1,040 MW), and are scheduled to be replaced with natural gas steam turbines that will individually operate at 526 MW of capacity (collectively 1,052 MW).[28] AES further notes that the Petersburg generating station was previously unable to demonstrate compliance with meeting certain Coal Combustion Residuals minimum standards that were

[25] See AES Indiana's '2025 Integrated Resource Plan Volume I' submitted to the Indiana Utility Regulatory Commission on October 31, 2025 at Pg. 272
[26] *Id.* At Pg. 273
[27] *Id.* At Pg. 75
[28] *Ibid.*

passed by the EPA in 2015 and updated in 2024, specifically the safety rules pertaining to ash ponds at the Petersburg generating station.[29] As a result, AES closed the ash ponds and on-site landfills, and continues to collect groundwater data at the Petersburg site in accordance with the Corrective Measures Assessment established in 2019, of which the groundwater samples indicate exceedances of groundwater protection standards.[30]

Understanding that Petersburg Units 3 and 4 are scheduled to retire and be repowered to natural gas generating stations in 2026 as a result of the 2022 IRP, United disagrees with AES's choice to replace units 3 and 4 with natural gas units rather than utilizing cleaner alternatives. Advanced energy technologies such as utility-scale wind and solar projects can replace the 1,020 MW of lost capacity as a result of Peterburg units 3 and 4 retiring in a cleaner and more cost-effective manner than natural gas. Additionally, United asserts that there is a large amount of uncertainty within the natural gas turbine supply chain currently which creates risk regarding AES's ability to construct a natural gas steam turbine in 2026. Recent industry reports from both Power Engineering and S&P suggest that wait times for gas turbine equipment is currently between seven or eight years and equipment costs have increased dramatically in recent years.[31] [32] Furthermore, a report from Lawrence Berkeley National Laboratory shows that the average processing time from interconnection request to an interconnection agreement is nearly 40 months for MISO and over 40 months for PJM.[33] This information indicates that the time to receive an interconnection agreement and receive gas turbine equipment could add up to over 10 years, making the construction of a natural gas steam turbine tumultuous to consider

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[29] *Id.* At Pg. 125

[30] *See* AES Indiana's '2025 Integrated Resource Plan Volume I' submitted to the Indiana Utility Regulatory Commission on October 31, 2025 at Pg. 126

[31] Power Engineering article 'Long lead times are dooming some proposed gas plant projects' by Kevin Clark on February 20, 2025 available here: https://www.power-eng.com/gas/turbines/long-lead-times-are-dooming-some-proposed-gas-plant-projects/

[32] S&P Global article 'US gas-fired turbine wait times as much as seven years; costs up sharply' by Jared Anderson on May 20, 2025 available here: https://www.spglobal.com/energy/en/news-research/latest-news/electric-power/052025-us-gas-fired-turbine-wait-times-as-much-as-seven-years-costs-up-sharply

[33] Berkeley Lab "Queued Up: 2025 Edition, Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2024" Published in December 2025 available here: https://emp.lbl.gov/publications/queued-2025-edition-characteristics

in 2026. Furthermore, natural gas plants are highly susceptible to changes in fuel price. Beyond an anticipated increase in fuel price (as the EIA projects average gas prices will increase to nearly $5/MMBtu in 2027), recent extreme weather events have highlighted the cost risks of an overreliance on natural gas.[34] During the recent nationwide cold snap in January 2026, certain regions of the country experienced the magnitude of these risks, as natural gas prices increased 63% in the week prior to Winter Storm Fern and power prices spiked up to $700/MWh in PJM, largely due to restricted gas supply. [35] [36] Finally, it is counterintuitive to replace a fossil fuel generating station that has an established track record of polluting local groundwater with a different fossil fuel that will continue to pollute the local environment (albeit in the form of air pollution). AES should therefore continue to consider cleaner alternatives to fill the lost capacity as a result of Peterburg units 3 and 4 retiring rather than repowering the plant using natural gas generators.

AES should also be transparent about potential costs of keeping Petersburg units 3 and 4 open if directed to do so under an Emergency Order, as was experienced by Northern Indiana Public Service Company ("NIPSCO"). In the case of NIPSCO, the first 90-day extension of NIPSCO's Schaefer units is expected to cost ratepayers $20.6 million in operating costs and an additional $33.7 million to replace old equipment.[37] A similar order could impact the Petersburg plants and AES should be proactive about communicating the total costs that would be passed on to ratepayers. Ultimately, United recommends that AES push back on an emergency order, if it were to come, and take a similar stance as recently seen by utilities in Colorado, who emphatically responded by detailing the poor economics of keeping open aging coal plants, where

[34] EIA article 'Short-Term Energy Outlook' on February 10, 2026 available here: https://www.eia.gov/outlooks/steo/report/natgas.php

[35] WSJ article 'Natural-Gas Prices Soar as U.S. Braces for Arctic Blast' by Ryan Dezember and Jennifer Hiller available here: https://www.wsj.com/us-news/natural-gas-prices-arctic-blast-6542d0a8

[36] Reuters article ' Power plant outages surge in Eastern US amid restricted gas supplies and frigid weather' by Tim McLaughlin and Arathy Somasekhar on January 26, 2026 available here: https://www.reuters.com/business/energy/power-prices-surge-winter-storm-spikes-demand-us-data-center-alley-2026-01-25/

[37] RTO Insider article 'MISO Stakeholders Should Decide Cost-sharing for DOE Coal Plant Orders' by Amanda Durish Cook available here: https://www.rtoinsider.com/124375-regulators-miso-community-decide-cost-sharing-coal-plants-emergency-extension/

replacement plans are already in place.[38] The added costs of keeping open the Petersburg units online will undermine AES's emphasis on affordability and lead to unnecessary costs borne by ratepayers.

3. *Lakefield Wind Park Power Purchase Agreement Future Considerations*

   Lakefield Wind Park is a 200 MW large-scale wind project located in Minnesota that AES has a PPA with to supply energy to AES until October 31, 2032.[39] AES has stated that because Lakefield Wind Park is not located in Indiana and does not receive capacity credit due to its interconnection service, AES is unlikely to retain past its expiration in 2032.[40] AES provides very little explanation regarding this PPA contract and the reason as to why Lakefield Wind Park does not receive capacity credit. Most importantly, AES fails to provide insight as to what resources it will consider to replace the shortfall that will exist as a result of the Lakefield Wind Park PPA expiring in 2032. United therefore requests that, in future IRPs, AES provides in-depth reasoning as to why it is not planning to retain the Lakefield Wind Park project or other similarly situated PPAs past the PPA expiration date. Furthermore, United recommends that AES begin the process for identifying what resources can be built, procured, or contracted with in order to meet the ~200 MW capacity shortfall that will occur when the Lakefield Wind Park PPA expires in 2031. Specifically, United recommends that AES look into similarly sized wind projects located in Indiana that would be able to replace the Lakefield Wind Park project.

4. *Advanced Transmission Technology and Grid-Enhancing Technology Future Considerations*

   AES asserts that it actively evaluates new transmission technologies and that Advanced Transmission Technologies ("ATTs") such as Dynamic Line Ratings ("DLR"), advanced power flow controllers, topology optimization, and advanced conductors can be faster to deploy and more cost-effective than traditional

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[38] CO Sun article ' Tri-State says no thanks to federal orders to keep Craig coal power plant open' by Michael Booth availabe here: https://coloradosun.com/2026/01/30/craig-tri-state-petition-coal-closure/

[39] *See* AES Indiana's '2025 Integrated Resource Plan Volume I' submitted to the Indiana Utility Regulatory Commission on October 31, 2025 at Pg. 165

[40] *Id.* at Pg. 75

transmission solutions.[41] AES specifically provided an example of the importance of ATTs in AES partnering with LineVision to install 42 DLR sensors across five transmission lines in AES Indiana and AES Ohio in late 2023. After one year, the data showed that DLR sensors provided an average of 43% capacity increase on AES Indiana's 345 kV line over existing static rating. Furthermore, the DLR sensors improved the situational awareness of the line capacity during different weather conditions, and AES plans to integrate the rates into its transmission energy management system to bring benefits into the real-time operation of its transmission system.[42] In addition to DLR, AES states that it has also evaluated advanced composite conductors such as ACCC and TS conductors for use on it transmission system. Despite this, AES claims that these ATT tools alone cannot generate electricity, and that ATT is a complement to, rather than a substitute for robust generation portfolios. United does not disagree with AES's statement that ATT tools cannot generate electricity, however, United asserts that ATT's, when cost effectively deployed, can allow a utility such as AES to avoid installing expensive and capitally-intensive generation resources. In fact, the example that AES provides where DLR usage resulted in 43% average capacity increase on AES's 345 kV lines only bolsters United's position that ATTs can help avoid the installation of expensive generation resources. United therefore recommends that AES utilize DLR sensors for a majority of its transmission lines, similar to the 42 LineVision sensors that were installed in 2023, in order to realize greater benefits associated with DLR such as increased capacity on transmission lines and real-time situational awareness of transmission line conditions. Additionally, United strongly recommends that AES deploy advanced conductors such as composite conductors for both new transmission line construction and reconductoring of old transmission lines to further realize the benefits of ATTs. United urges AES to continue to evaluate ATT opportunities on its transmission system and further understand the benefits associated with ATTs such as avoided transmission and generation costs.

[41] *See* AES Indiana's '2025 Integrated Resource Plan Volume I' submitted to the Indiana Utility Regulatory Commission on October 31, 2025 at Pg. 38
[42] *Ibid.*

5. *Large Load Customers: Load Considerations & Supply Flexibility*

As discussed in detail above, AES has taken the unique approach in the 2025 IRP to develop two preferred portfolios which hinge solely on whether or not large load customers come online in AES's service territory. Currently, AES does not have any new large load customers that have signed agreements or contracts to operate within AES's service territory, however, AES has received inquiries from large load customers expressing interest in development within the service territory. As a result, AES's load growth (as developed using Itron's Statistically Adjusted End-Use methodology) is expected to be modest, resulting in a 0.7% annual growth rate in forecasted annual energy demand and 0.8% annual growth rate in forecasted annual peak demand.[43] To account for the possibility that new large load customers do come online in AES's service territory, AES included such load in its forecasting by separately incorporating the new center load in its capacity expansion model as four possible blocks of additional load (no, low, mid, and high penetration).[44] The no-load scenario resulted on 0 MW of additional load by 2035, the low-load scenario resulted in 500 MW of additional load by 2035, the mid-load scenario resulted in 1,500 MW of additional load by 2035, and the high-load scenario resulted in 2,500 MW of additional load by 2035.[45] As discussed above, AES's two preferred portfolios modeled both the no-load scenario and the mid-load scenario, with the mid-load data center scenario resulting in the forecasted addition of 860 MW of battery storage and 700 MW of Natural Gas Combine Cycle (NGCC) by 2032.[46]

United is concerned with the large amount of additional resources that AES would need to obtain in order to accommodate the potential new load that could be brought to AES's service territory, specifically with regards to the 700 MW of NGCC resources. United does not necessarily believe that the best way to accommodate such large loads is for the utility to build large-scale generation resources. Because the large load will have a substantial impact on a utilities energy planning requirements (such as the IRP process), United believes that contracts/agreements/tariffs with new large load customers should address

[43] *See* AES Indiana's '2025 Integrated Resource Plan Volume I' submitted to the Indiana Utility Regulatory Commission on October 31, 2025 at Pg. 48
[44] *Id.* At Pg. 72
[45] *Id.* At Pg. 73
[46] *See* AES Indiana's '2025 Integrated Resource Plan Volume I' submitted to the Indiana Utility Regulatory Commission on October 31, 2025 at Pg. 262

how the energy will be sourced and that such customers should have a choice in how a significant portion of their load will be met. Specifically, any agreement or tariff should generally provide for the customer's ability to choose the type of resources desired, such as generation, transmission, or distribution resources that are sources via utility procurements, bilateral/trilateral contracting, behind-the-meter, and/or front-of-meter collocation arrangements. This type of arrangement would allow for the new large load customer to have more say in how their load is served, and will allow the utility to avoid constructing expensive large-scale resources thus insulating existing customers from the high cost associated with serving the new load. To divulge on this topic more, any agreement or tariff should provide options for the large load customer to deploy resources via on-site (or contiguous-site) supply to reduce customer load or provide monetary contributions to existing EE, DR, VPP, or demand flexibility programs that deliver broader grid benefits and create headroom that can lower the cost and increase the speed of connecting new large load customers. These options may not completely alleviate the need for new generation to serve new load, however, such contributions could reduce/mitigate the amount of generation needed to be constructed. To further support this position, AES even states that it is particularly interested in exploring how large loads might actively participate in demand-side programs, such as targeted DR or customized EE initiatives, as this approach could help reduce peak demand, defer infrastructure upgrades and improve overall flexibility.[47]

In addition to allowing new large load customers greater choice over what resources will meet their load requirements, United asserts that there is a large amount of uncertainty within the natural gas turbine supply chain currently which allows for pause regarding AES's ability to construct a NGCC generator by 2032. The uncertainty surrounding the natural gas turbine supply chain is discussed at length in the section of these comments focused on the Petersburg Units 3 and 4 Retirement and Future Replacement, and United asks readers to refer to this section for more information on this topic. United therefore recommends that AES, in any agreements, tariffs, or contracts, allow potential large load customers the ability to make decisions on the resources that will be

[47] *See* AES Indiana's '2025 Integrated Resource Plan Volume I' submitted to the Indiana Utility Regulatory Commission on October 31, 2025 at Pg. 273

supplying their load in order to reduce AES's need to construct large-scale generation resources such as a NGCC generator.

Conclusion:

United greatly appreciates the opportunity to provide comments on AES's 2025 IRP and notes that it has identified concerns and potential improvements on the following topics of the 2025 IRP: 1) DR and EE Program Considerations, 2) Petersburg Units 3 and 4 Retirement and Future Replacement, 3) Lakefield Wind Park PPA Future Considerations, 4) ATT and Grid-Enhancing Technology Future Considerations, and 5) Large Load Considerations and Supply Flexibility. United has specific considerations and recommendations on each of the topics within these comments and recommends that AES consider the suggested improvements in each topic area for applicability in future IRPs. United respectfully asks that the Commission and specifically the Commission's Director of Research, Policy, and Planning to consider these comments and recommend that AES adopt them in future IRP development efforts.

Brett Sproul

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