March 6, 2026

Dr. Bradley Borum, Director of Research, Policy, and Planning
Indiana Utility Regulatory Commission
PNC Center, 101 W. Washington Street, Suite 1500E
Indianapolis, IN 46204

Re: Comments of Clean Grid Alliance on AES Indiana's 2025 IRP

I. INTRODUCTION

Clean Grid Alliance ("CGA") is a membership-based, 501(c)(3) nonprofit organization with a mission of advancing clean energy in the Midwest through participation in the Midcontinent Independent System Operator ("MISO") stakeholder process and engagement before public utility regulatory commissions and state legislatures across MISO's North and Central footprint. CGA's membership includes more than 80 companies representing clean energy developers, clean energy and environmental nonprofit organizations, data centers, and businesses providing goods and services to the clean energy industry.

CGA respectfully submits these comments on the 2025 Integrated Resource Plan ("IRP") of AES Indiana ("AES" or "the Utility"). CGA participated in three of the four technical meetings hosted by AES and attended each of the Utility's four public advisory meetings.[1] CGA also utilized the discovery process to gain clarification; suggest modifications to modeling inputs, assumptions, and scenarios; and propose new sensitivities or modeling modifications following several of the Utility's technical meetings. CGA is deeply appreciative of not only the range of participation opportunities afforded to stakeholders by AES, but also of the thorough presentations and robust discussion in the technical meetings especially. We thank the AES Indiana planning team for engaging with us and for being responsive to our discovery questions and feedback throughout the development of this IRP.

However, AES's 2025 IRP contains modeling inputs and assumptions in the Reference Case that CGA views as problematic and introduces risk related to both the resource portfolios and large loads in the Preferred Portfolios. Specifically, CGA has concerns with the following:

- capital cost assumptions,
- natural gas price forecast,
- the resource accreditation values applied to future wind generation,
- the supply-side resources modeled and the modeling approach, and
- the large load forecast.

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[1] CGA attended the July 17th, September 3rd, and October 15th Technical Working Group meetings.

Broadly speaking, CGA recommends that AES revisit these inputs before proceeding with resource actions under the 2025 IRP Preferred Portfolios, particularly those of the Short-Term Action Plan. Our recommendations are further discussed in Section IV of these comments.

II. PREFERRED PORTFOLIOS OVERVIEW

AES Indiana developed sixteen candidate portfolios by testing four different load forecasts across four different scenarios.[2] The four IRP scenarios envision separate, unique futures "that represent different worldviews."[3] The "Reference Case" scenario represents current market and federal policy conditions; the "High Regulatory: Environmental" scenario contemplates strong environmental and carbon emission regulations and policy incentives favoring renewable technologies; the "Gas Infrastructure Challenges" scenario forecasts high natural gas prices; and the "Stable Markets" scenario shows the electric sector returning to a period of relative market stability such as that preceding the COVID-19 pandemic. The four load forecasts assume futures where AES adds no data center load, adds "low" data center load up to 500 MW, adds "mid" data center load up to 1,500 MW, and adds "high" data center load up to 2,500 MW, all by 2035.

Through the process of testing these conceptual load futures across the four scenarios, AES selected two Preferred Portfolios: the Reference Case with No Data Center Load and with Mid Data Center Load. Neither portfolio includes new wind, solar, or multi-day energy storage through 2045. Instead, the No Data Center Load portfolio relies on demand response programs ("DR"), energy efficiency programs ("EE"), and incremental additions of up to 100 MW of storage to serve relatively flat load through the early 2040s, while the Mid Data Center Load portfolio utilizes similar levels of DR and EE but scales storage capacity to 860 MW in addition to adding 1,500 MW from new combined cycle gas turbine ("CCGT") and reciprocating internal combustion engines ("RICE").[4] The bulk of these resource additions occurs within the Short-Term Action Plan period from 2026-2032.[5]

III. MODELING INPUTS & ASSUMPTIONS IN THE REFERENCE CASE

AES describes the Reference Case underpinning its Preferred Portfolio thus:

> *"The Reference Case scenario represents all projected future laws and changes to existing laws and regulations, a base case view of load and commodity markets, and a starting point for new resource costs that reflect current market pricing."*[6]

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[2] AES Indiana 2025 IRP Volume 1 ("2025 IRP"), "Executive summary, 2025 IRP framework," pp. 15-16.
[3] *Ibid.*
[4] 2025 IRP, "Figure 9-5: Reference case – Installed capacity (MW) by resource type and load case," p. 167. *Also see* "Section 5: Load research, load forecast, and forecasting methodology" starting on p. 46, and "Data center load discussion", pp. 71-72.
[5] 2025 IRP, Executive summary, "Preferred resource portfolio and Short-Term Action Plan," pp. 14-15.
[6] 2025 IRP, Section 8, "Resource portfolio modeling." See pp. 130-132.

In other words, under this scenario, greenhouse gas rules promulgated by the Environmental Protection Agency under the Biden Administration ("the GHG Rules") are assumed to be repealed; tax credits for utility-scale wind, solar, storage, and nuclear reflect changes from the new federal tax law (the "OBBBA"); capital costs and fuel prices are based on the current market; and, as described above, a relatively flat load forecast outside the variable Data Center Load forecasts.

Further, access to the wholesale market was uniformly enabled at 20% of the Utility's annual load through 2045.[7] AES did not account for the expected impact of MISO's Long Range Transmission Plan ("LRTP").

Although not reflected in the final Reference Case scenario, at the request of CGA, AES also undertook a model run of the Reference Case across each Data Center Load trajectory reinstating production and investment tax credits for wind and solar in the early 2030s to evaluate whether their resumption in the mid-term of the IRP planning period would materially influence the capacity expansion portfolio.[8] CGA thanks the AES planning team for accommodating this request, which ultimately did not lead to the model choosing wind and solar resources in either of the Preferred Portfolios. However, problematic inputs and assumptions for capital costs, natural gas prices, and resource accreditation in the Reference Case may have contributed to that outcome, as we discuss below. We also discuss the omission of longer-duration, multi-day, and lithium-ion energy storage alternatives from the supply-side resource options and the omission of the LRTP Tranche 1 projects from the capacity expansion modeling.

Capital costs. AES provided base capital costs for new resources starting in 2026, as well as fixed operating and maintenance ("O&M") costs starting in 2030.[9] The cost projections for solar and stand-alone storage are reasonable and aligned with regional data. However, the capital cost assumptions for wind and hybrid solar and storage appear high. In a review of 2024 project costs, Lawrence Berkeley National Labs found that solar and storage hybrids averaged $2,500/kW, with the storage component adding approximately $1,000/kW to total system costs.[10] However, AES estimated that storage would add more than $1,300/KW to total costs.[11] Regarding wind, AES explained to CGA that it received very few responses to its 2024 RFP, with none located in Indiana, so that the limited number of bids contributed to the relatively high capital cost estimate.

One explanation for the high capital cost for solar and storage hybrids could be related to the Utility's 2024 Request for Proposals ("RFP"), which contained a <u>production</u> requirement guarantee of 95% for solar and storage power purchase agreements ("PPAs").[12] CGA is concerned

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[7] 2025 IRP. Section 8.3.1. "Capacity expansion setup and constraints," pp. 144-146.
[8] 2025 IRP, Section 8, p. 149.
[9] 2025 IRP. Section 6.2, "Supply-side resource options", starting p. 77.
[10] Lawrence Berkeley National Labs. "U.S. utility-scale solar: 2025 Data update." (October 2025.) Accessed at: https://emp.lbl.gov/sites/default/files/2025-10/Utility%20Scale%20Solar%202025%20Edition%20Slides.pdf
[11] 2025 IRP. Section 6.2.3. In particular, see Figure 6-11: "Wind, solar, and storage unit parameters," p. 82.
[12] AES. "2024 RFP for power supply generation facilities and/or PPAs." See "Form solar energy and PPA," section 7.4, p. 14. (Issued September 27, 2025.) Accessed at: https://www.aesindianarfp.com/

this provision contributed to higher bids as this requirement is, firstly, about 10-20% higher than is considered reasonable by our independent power producer ("IPP") members, and secondly, atypical of PPAs. Our IPP members more frequently see utility RFPs including an availability guarantee which requires the facility to be available for 90-95% of all possible hours within a given planning year instead.

An explanation for the few wind proposals, with requisite high capital costs, is likely related to problems with siting and permitting in Indiana. More than 80% of Indiana counties have adopted restrictions or moratoria on different types of energy projects, including wind.[13] However, Indiana state agencies and elected officials are actively working to resolve project permitting constraints, indicating the outlook for clean energy project development will improve.[14]

Natural gas price. The commodity curves used by AES in the Reference Case are based on the long-term assumption that gas prices will stay below $4/MMBtu through 2045.[15] Yet, market analysts predict that gas fuel prices will average *above* $4/MMBtu, especially between now and 2030, for reasons including growth in the natural gas export market, supply and demand imbalance, and gas infrastructure constraints.[16] Prior to AES' second technical meeting, the U.S. Energy Information Administration ("EIA") released a Short-Term Energy Outlook showing Henry Hub spot prices averaging $4/MMBtu in 2025 – nearly doubling from $2.20/MMBtu in 2024 – and increasing to $4.90/MMBtu in 2026.[17] The most recent EIA outlook provides a more moderate 2026 forecast of $3.50/MMBtu, but the agency expects 2027 prices will skyrocket to $4.60/MMBtu as demand outpaces production.[18] Following the release of the EIA's June outlook and the Utility's second technical meeting, CGA encouraged AES to adopt the higher gas prices from the Gas Infrastructure Challenges scenario in the Reference Case, but AES declined to do so.

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[13] CGA and the American Clean Power Association found that 74 of Indiana's 92 counties deny, severely restrict, or effectively prohibit utility-scale energy storage, solar, and wind development, according to a January 2026 analysis.
[14] Indiana Capital Chronicle. "Indiana energy secretary blasts local moratoriums, calls energy development 'patriotic' task." (September 17, 2025.) Accessed at: https://indianacapitalchronicle.com/2025/09/17/indiana-energy-secretary-blasts-local-moratoriums-calls-energy-development-patriotic-task/
[15] 2025 IRP, Section 8, p. 138-141.
[16] Argus Media. "Viewpoint: US gas price moves may detach from weather." (December 31, 2025). Accessed at: https://www.argusmedia.com/en/news-and-insights/latest-market-news/2770994-viewpoint-us-gas-price-moves-may-detach-from-weather. *Also see* EIA. Short-Term Energy Outlook. (December 9, 2025.) Accessed at: https://www.eia.gov/outlooks/steo/report/natgas.php. *Also see* The Wall Street Journal. "U.S. natural gas futures rise as front month expires." (December 29, 2025.) Accessed at: https://www.wsj.com/finance/commodities-futures/u-s-natural-gas-futures-gain-ahead-of-delayed-storage-data-12a46a39?gaa_at=eafs&gaa_n=AWEtsqcvJrX3mgR50wDuM8q6A4Me_GuVSoGstHNxHFfqrVW-bObNvQjhgZCY06UbraU%3D&gaa_ts=695d32ee&gaa_sig=pLI4FeW-ZjmRpw39MnGjf08LrkkuIuLPmZp7jHRuG2AtSOslf-9U0t8sYmE_jpWujRjxoeF1JSOMn-aH1wqcaA%3D%3D. *Also see* IEEFA. "LNG exports and U.S. power price." (August 4, 2025.) Accessed at: https://ieefa.org/resources/lng-exports-and-us-power-price
[17] U.S. EIA. "Short-Term Energy Outlook." (June 2025.) Accessed at: https://www.eia.gov/outlooks/steo/archives/Jun25.pdf
[18] U.S. EIA. "Short-Term Energy Outlook." (January 13, 2026.) Accessed at: https://www.eia.gov/outlooks/steo/pdf/steo_full.pdf

This scenario design choice suggests the Preferred Portfolios are likely to be riskier and far less affordable in reality than as modeled in the IRP, and hints at why the model selected gas resources over wind and solar even when the tax credits were reinstated in the Reference Case model runs described above. For example, in the Gas Infrastructure Challenges scenario, 50 MW of solar are selected in the Mid-Data Center case, which holds assumptions aside from the higher natural gas prices and firm gas transportation costs equal to the Reference Case.[19] The High Regulatory: Environmental scenario selects wind, solar, and energy storage in all Data Center Load cases due to high capital costs for thermal resources and high gas fuel prices, again demonstrating that clean energy resources are competitive against thermal resources when both the capital costs and fuel prices are properly accounted for.[20] Further, in a comparison of portfolios serving large loads in MISO with primarily thermal or primarily renewable resources, analysts found higher operational costs driven by fuel costs under the thermal-only portfolio, stressing the point that over-reliance on natural gas would increase fuel price exposure across a utility's rate base.[21]

CGA is well aware that various factors, including resource accreditation (addressed below) and production profiles as well as cost, contribute to the viability of a given portfolio. However, these comparisons demonstrate that the Reference Case does not fairly compare the cost risk of thermal resources to clean energy resources in either the No- or Mid- Data Center Load case.[22]

Resource accreditation. AES derived resource accreditation values from "a combination of sources, including indicative MISO direct loss of load ("DLOL") modeling, MISO-provided AES Indiana indicative DLOL values for existing resources, and internal projections for future penetration levels of various technologies, particularly [for] solar and storage."[23] AES applied unit-specific DLOL values from MISO for the Utility's Hoosier Wind resource as a generic proxy for future wind accreditation,[24] but Hoosier Wind was placed in service in 2009.[25] CGA observes that unit-specific capacity accreditation for Hoosier Wind diverges significantly from MISO's resource class-level accreditation values under the DLOL construct,[26] and is concerned that basing accreditation for future wind resources on the performance of facilities more than 15 years old will not adequately predict their performance.

Like one-time capital costs and on-going O&M costs, capacity accreditation has a profound effect on modeling results and thus, on a portfolio's overall viability. The point of accrediting

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[19] 2025 IRP, Section 9, "IRP results." See p. 163 and pp. 178-189.
[20] 2025 IRP, Section 9. See pp. 189-200.
[21] GridLab and Energy Futures Group ("EFG"). "Large loads and natural gas price risk." (January 6, 2026.) Accessed at: https://gridlab.org/portfolio-item/large-loads-and-natural-gas-price-risk-2/
[22] Risks related to over-reliance on natural gas as a fuel source are discussed in Section IV of these comments.
[23] 2025 IRP. Section 6.2.2, "Capacity accreditation." See pp. 79-81.
[24] 2025 IRP. Section 6.2.2. See p. 80.
[25] 2025 IRP. Section 6.1.1, "Existing supply side resource". See Fig. 6.4: "AES Indiana existing and IURC-approved renewable and storage" on p. 76.
[26] For example, for wind's most productive season (i.e., winter), AES accredits the resource at just 17% of ICAP while MISO does so at 22%. *See* 2025 IRP Section 6.2.2 and MISO, "Planning Year 2025-2026: Indicative DLOL results", published April 2025.

resources is to quantify the level of ICAP that will probably contribute to resource adequacy during peak periods. The risk is that understating or overstating available capacity will lead to adverse outcomes like over- or under-built systems, or loss of load or unserved energy events. To hedge against these risks, CGA urges the Indiana Utility Regulatory Commission ("IURC") to investigate whether the values put forth by AES can be reasonably applied to future wind.

Supply-side resources and capacity expansion modeling. AES conducted sensitivity analysis of transmission deployment but did not specifically account for the increased transmission capacity and other transmission benefits MISO's regional LRTP program is expected to deliver to Indiana by the end of the Short-Term Action Plan period (i.e., by 2032). However, Lawrence Berkeley National Labs recommends the modeling best practice of making transmission a selectable resource, allowing "endogenous transmission builds" to mimic planned regional transmission expansion to "see how changes shape optimized utility resource portfolios and costs."[27] The benefit/cost ratio for Tranche 1 in MISO Zone 6 is estimated to range from 2.7-3.9 and result in potential total cost savings of up to $7 billion.[28] Importantly, Tranche 1 projects are largely on track to meet MISO's goal of energizing the entire portfolio by the early 2030s.[29] Yet, AES did not evaluate future cost-savings opportunities against the supply-side investments in the Reference Cases, a gap which CGA believes undermines the proposed capacity expansion portfolio.

As to supply-side resource technology options, AES modeled what it designated "commercially viable technologies," including solar and storage hybrids and 4-, 6-, and 8-hour stand-alone storage systems.[30] While AES did not evaluate other hybrid combinations, the Utility noted the choice to develop a different type of storage hybrid (e.g., gas and storage) "would be project dependent" and potentially proposed in a future project approval proceeding.[31] AES also did not evaluate energy storage from 10- and up to 24- hours ("long-duration") or multi-day energy storage systems, or energy storage technology options beyond lithium-ion ("LI") batteries, stating in a technical meeting the Utility would need to see further proof of viability before allowing the model to select those resource options.[32] Regarding AES' storage-related decisions in supply-side resource modeling, CGA supports the development of both renewable and thermal storage hybrids

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[27] Lawrence Berkeley National Laboratory and Synapse Energy Economics. "Best practices in IRP: A guide for planners developing the electricity resource mix of the future." (November 2026.) See "Best Practice 26. Consider transmission alternatives and infrastructure expansion," pp. 48-49. Accessed at: https://www.energy.gov/sites/default/files/2024-12/best_practices_irp_nov_2024_final_optimized.pdf

[28] See MISO. LRTP Workshop, "LRTP Tranche 1 portfolio detailed business case." https://cdn.misoenergy.org/20220329%20LRTP%20Workshop%20Item%2002%20Detailed%20Business%20Case623671.pdf

[29] MISO. "LRTP: Overview." Accessed on January 6, 2026, at: https://www.misoenergy.org/planning/long-range-transmission-planning/. Also see Clean Grid Alliance. "Q&A: What is long-range transmission planning and why is It important?" (December 2025). Accessed at: https://cleangridalliance.org/blog/254/qa-what-is-long-range-transmission-planning-and-why-is-it-important

[30] 2025 IRP, Section 6, "Resource options." See p. 77 and pp. 80-84.

[31] 2025 IRP Public Advisory Meeting #1 (January 29, 2025.) AES responded thus to CGA's query as to whether the Utility would consider storage hybrids beyond solar and storage alone.

[32] 2025 IRP Technical Meeting #2 (July 17, 2025.) Several stakeholders expressed concern about the limited storage technology options.

where technically feasible and cost-effective and where interconnection opportunities exist, but cautions the exclusion of long-duration and multi-day energy storage, and LI storage alternatives from the supply-side options is a significant omission.

Utilities and state procurement entities from across the U.S. are actively procuring long-duration and multi-day storage. To list two, the California Public Utilities Commission tasked the statewide energy office with procuring up to 1 GW of long-duration storage with at least a 12-hour discharge capability and up to 1 GW of multi-day storage to support the state's decarbonization goal,[33] and the New York Public Service Commission directed the New York State Energy Research and Development Authority to target 20% long-duration storage in competitive bulk energy storage procurements.[34]

Many technologies are capable of responding to this charge. For example, LI battery storage design has evolved to the point that discharge duration of a given LI battery can be varied to serve longer-duration needs of 6-12 hours, without limitation from a battery or inverter perspective, and 70% of long-duration projects planned for operation by 2030 utilize LI.[35] Additionally, the following pilot projects demonstrate the viability of multi-day energy storage and non-lithium-ion storage technologies. In Fall of 2025, Peak Energy, utilities, and IPP partners deployed a 3.5 MWh sodium-ion battery in the first grid-scale pilot of this LI alternative.[36] Form Energy ("Form") and Xcel are on-track to place into service in 2026 a 10 MW/1,000 MWh iron-air storage system in the utility's Minnesota service area,[37] and Form, Google, and Xcel just announced plans for the 2028/2029 deployment of a 300 MW iron-air battery that will help power a Google data center in Minnesota.[38]

IV. RISK UNDER THE PREFERRED PORTFOLIOS

Lack of resource diversity. AES is – and under the Preferred Portfolios would remain – heavily dependent on a single fuel source: natural gas. As presented during the first 2025 IRP Public

[33] California Public Utilities Commission ("CPUC"). "CPUC advances clean energy with centralized procurement strategy." (August 26, 2024). Accessed at: https://www.cpuc.ca.gov/news-and-updates/all-news/cpuc-advances-clean-energy-with-centralized-procurement-strategy

[34] New York Public Service Commission. Case 18-E-0130. *In the matter of energy storage deployment program.* (June 20, 2024). "Order establishing updated storage goal and deployment policy."

[35] Sightline Climate. "H126 LDES leaderboard." (January 28, 2026). Accessed at: https://www.sightlineclimate.com/research/h126-ldes-leaderboard

[36] Electrek. "The US's first grid-scale sodium-ion battery is now online." (September 25, 2025). Accessed at: https://electrek.co/2025/09/25/us-first-grid-scale-sodium-ion-battery-is-now-online/ek

[37] Minnesota Public Utilities Commission. Docket No. M-23-119. *In the matter of the petition of Northern States Power Company d/b/a Xcel Energy for approval of a long-duration energy storage pilot project at Sherco. (*Filed March 6, 2023).

[38] Xcel Energy. "Xcel Energy to power new Google data center in Minnesota." (February 24, 2026). Xcel will bring 1,900 MW of new clean energy online, including the largest battery deployment in the world via Form's battery. Accessed at: https://newsroom.xcelenergy.com/news/xcel-energy-to-power-new-google-data-center-in-minnesota

Advisory meeting, over two-thirds of the Utility's installed capacity is gas-fired generation.[39] More than half of the capacity added in the Reference Case, Mid Data Center Load scenario is likewise gas-fired. This lack of supply-side resource diversity and the extreme reliance on a finitely available fuel source is a significantly risky strategy which is inconsistent with the Department of Energy's recommendation that utilities take a diversified "portfolio approach" to ensuring resource adequacy.[40] These risks were most recently observed during Winter Storm Fern in January 2026, when regions of the country experienced blackouts and spikes in power prices due to failing natural gas infrastructure. In PJM, extreme cold temperatures constrained natural gas supplies, leading to outages and price surges ranging from $400 to $700/MWh during the storm's peak.[41]

Renewables have been shown to mitigate blackout intensities and improve extreme weather resiliency in grids with high variable resource penetration,[42] and both LDES and multi-day energy storage are viewed as critical hedges against power supply interruptions and equipment failures during extreme weather.[43] Over-dependency on gas generation also runs counter to Indiana's Five Pillars of Energy Policy, which established key metrics including <u>resiliency</u>, <u>reliability</u>, and <u>affordability</u> (the other two being stability and environmental sustainability).[44] As we addressed fuel price risk in Section III above, we focus here on affordability risk related to capital costs, reliability and resiliency risks, and future regulatory risk of the gas-dependent IRP.

Demand for gas turbines is reflected in extraordinary unit costs, which have more than doubled in recent years and which are expected to persist or increase through the early 2030s.[45] Indeed, AES modeled a CCGT costing $2,771/kW,[46] more than double the $1,100/kW estimated for 2026 in the Utility's 2022 IRP.[47] Not only are prices up, but so are unit wait times: GE Vernova just increased its gas turbine backlog to 80 GW and extended deliverability through 2029, and a

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[39] 2025 IRP Public Advisory Meeting #1. See Presentation, "Overview of existing resources," slide #30. Accessed at: https://www.aesindiana.com/sites/aesvault.com/files/2025-01/IRP-Public-Advisory-Meeting-1-2025-AES-Indiana.pdf

[40] U.S. Department of Energy. "The future of resource adequacy." (April 2024.) Accessed at: https://www.energy.gov/sites/default/files/2024-04/2024%20The%20Future%20of%20Resource%20Adequacy%20Report.pdf

[41] Reuters. "Power plant outages surge in Eastern US amid restricted gas supplies and frigid weather." (January 26, 2026). Accessed at: https://www.reuters.com/business/energy/power-prices-surge-winter-storm-spikes-demand-us-data-center-alley-2026-01-25/?utm_campaign=Newsletter&utm_medium=email&_hsenc=p2ANqtz-_QBRinIkaHI16X6wKsZL-Ho7A-p0Ewyz33RV6fgep4dRHTUjNKphaPBB18FzNMVMMQoqLzDp79JhyABNvi-bEMEMNqZw&_hsmi=400360088&utm_content=400360088&utm_source=hs_email

[42] Nature Energy. "Impacts of renewable energy resources on the weather vulnerability of power systems." (October 21, 2024.) Accessed at: https://www.nature.com/articles/s41560-024-01652-1

[43] CRA. "LDES: Leading indicators." (Winter 2023.) Accessed at: https://media.crai.com/wp-content/uploads/2024/03/28175856/IRA-Leading-Indicators-Winter-2023.pdf

[44] Indiana Office of Energy Development. "Indiana's Energy Policy." Accessed at: https://www.in.gov/oed/indianas-energy-policy/

[45] GridLab, "The new reality of power generation: An analysis of Increasing Gas Turbine Costs in the U.S.," (September 2025), accessed at: https://gridlab.org/portfolio-item/gas-tubine-cost-report/

[46] 2025 IRP. Section 6.2.4. "Natural gas resources." Starting on p. 84.

[47] 2025 IRP. Section 9.2.2. "Candidate portfolio summaries." P. 203.

record number of orders transacted by Siemens Gas Services in the first quarter of 2025 led to a record backlog for the company.[48]

Relatedly, the same demand driving up turbine costs is tightening supply. Gas infrastructure and transport constraints are of increasing concern to the regulatory community.[49] Yet, the same forces contributing to clean energy siting issues (e.g., local challenges, project permitting requirements, and project delays) call the viability of timely gas storage and gas pipeline development into question. Meanwhile, utilities without firm access to the fuel source (during extreme weather conditions, in particular) are at increased reliability risk.

Finally, future environmental regulatory policies requiring carbon emissions abatement could make gas-fired generation riskier to operate from both efficiency and affordability perspectives. AES assumed the GHG Rules would be repealed and thus, did not model the cost or operational effect of emissions abatement.[50] However, a future administration taking a different approach to carbon policy could reinstate similar or more aggressive abatement measures. The Utility's High Regulatory: Environmental scenario provides a window into this possible future: neither the No Data Center nor the Mid Data Center Load cases add gas-fired generation due to the high capital costs and capacity factor limitations modeled.[51]

Given these risks, CGA offers several recommendations in Sections V(A) and (C) below. In short, we encourage the IURC to dissuade AES from overreliance on natural gas generation and unrealistic capital, O&M, and fuel cost estimates, and to urge AES to pursue renewable generation and storage, including long-duration and multi-day energy storage, for their contributions to a more diversified generating portfolio, long-term cost-effectiveness, and speed to deployment. Tens of GWs of these resources are currently in the MISO generator interconnection queue and are expected to come online before 2030, likely several years before new gas turbines will be available.

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[48] *See* Utility Dive, "GE Vernova expects to end 2025 with an 80-GW gas backlog that stretches into 2029," (December 11, 2025), accessed at: https://www.utilitydive.com/news/ge-vernova-gas-turbine-investor/807662/?utm_source=Sailthru&utm_medium=email&utm_campaign=Issue:%202025-12-11%20Utility%20Dive%20Newsletter%20%5Bissue:79762%5D&utm_term=Utility%20Dive; *and* S&P Global, "US gas-fired turbine wait times as much as seven years; costs up sharply," (May 20, 2025), accessed at: 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#:~:text=US%20gas%2Dfired%20turbine%20wait,EN

[49] The National Association of Regulatory Utility Commissions established the Taskforce on Gas-Electric Alignment for Reliability ("GEAR") in November 2023 to "better align the gas and electric industries to maintain and improve the reliability" of the intertwined energy systems. More information, including GEAR's recent recommendations, is available at: https://maxxwww.naruc.org/forms/committee/CommitteeFormPublic/viewExecCommittee?id=13B6350000001C&multicolumns=1. *Also note* the Multi-utility Emergency Cooperability Work Group, convened by the Michigan Public Service Commission in December 2025, to "review and discuss cooperability between natural gas and electric utilities during multi-utility emergency events." More information about the work group is available at: https://www.michigan.gov/mpsc/commission/workgroups/multi-utility-emergency-cooperability-workgroup

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[51] 2025 IRP. Section 9.2.2. "Candidate portfolio summaries." Starting on p. 189.

Large load uncertainty. In creating the scenarios for this IRP, AES Indiana segmented its data center load forecast from the forecasts for residential, commercial, and other industrial loads – an approach which is becoming a widely considered best practice.[52] AES then developed the four modeled levels of data center load (i.e., No, Low, Mid, and High Data Center Load) "based on customer discussions, national market trends, interconnection data, and industry forecasts."[53] Given the energy-intensive nature of the data center industry and the scale of its demand for electricity, AES acknowledges that such load "materially affects long-term planning outcomes within an IRP" by accelerating the need for resource additions.[54] Thus, the Utility evaluated the four data center load levels as unique scenarios, and ultimately selected the Mid Data Center Load case adding up to 1,500 MW by 2035 as the basis for the second of its two Preferred Portfolios. Neither the No Data Center Load nor the Mid Data Center Load portfolios propose any new renewable investments – and the No Data Center Load scenario adds minimal resources overall – but the dual Preferred Portfolio structure would allow significant investment in new gas capacity in the event large load customers do appear, despite the risks detailed above.

CGA acknowledges that today's planning environment is uncertain, but commitments from data center companies to take service from AES are notably absent from the factors contributing to the Utility's load-growth scenarios. Further, at the time of filing this IRP, AES had not publicly announced any service agreement with a data center customer, only that AES had "received inquiries from new large load customers."[55] CGA fundamentally disagrees with AES Indiana's decision to include uncommitted large loads in the IRP – and thus, in the Short-Term Action Plan guiding the Utility's near-term investments.[56] Doing so deviates from consensus forming across the electric sector related to large load forecasting best practices. For example, the Large Loads Task Force convened by the Electric Systems Integration Group recommends a "maturity assessment" that excludes projects not meeting maturity criteria from load forecasts.[57] Charles River Associates, in a review of large load planning considerations solicited by Ameren Missouri, recommends "phased infrastructure investment" based on confirmed loads and/or key

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[52] *See* Charles River Associates ("CRA"), "Utility planning best practices: Data center load considerations," in MO PSC Docket No. EO-2026-0088, "Annual IRP update: Appendix A," pp. 1-2 (filed October 30, 2025); Electric Systems Integration Group ("ESIG") Large Loads Task Force, "Forecasting for large loads: Current practices and recommendations," pp. 1-2, accessed at: https://www.esig.energy/wp-content/uploads/2025/12/ESIG-Large-Loads-Forecasting-report-2025.pdf; and EFG, "Review of large load tariffs to identify safeguards and protections for existing ratepayers," (January 28, 2025), pp. 28-29, accessed at: https://energyfuturesgroup.com/wp-content/uploads/2025/01/Review-of-Large-Load-Tariffs-to-Identify-Safeguards-and-Protections-for-Existing-Ratepayers-Report-Final.pdf.
[53] 2025 IRP, p. 72.
[54] *Ibid.*
[55] *Ibid.*
[56] Note that while AES included resource actions associated with Mid Data Center Load in the Short-Term Action Plan, the Utility will only pursue certain investments if large loads "commit". However, under this approach, AES would receive a nod towards regulatory approval of projects included in the Reference Case, Mid Data Center Load portfolio. *See* 2025 IRP, Figure 0.1: "Short-Term Action Plan," p. 15.
[57] ESIG Large Loads Task Force. "Forecasting for large loads." Pp. 34-35.

development timelines.[58] The Energy Futures Group recommends utilities "assess the likelihood of the load addition using elements such as where the new load is in the interconnection process, whether a feasibility study has been conducted, and whether the location has been procured, such as through a land sale/lease contract or local zoning approval."[59] Accordingly, the Colorado Public Utility Commission recently ordered the Public Service Company of Colorado to produce contractual commitments, including a signed electric and interconnection service agreement (respectively, "ESA" and "IA"), for any large load to be included in the utility's resource planning forecast.[60]

In short, speculative loads (i.e., those without executed service agreements or long-term contracts) should not be incorporated into a regulatory process that lays the groundwork for future resource actions, such as capital investment on the order of what is contemplated here.[61] Furthermore, the State of Indiana already provides utilities with a venue – outside the IRP process – by which to earn expedited approval for capacity required by the addition of new large customers through the Expedited Generation Resource ("EGR") planning and associated procurement processes, which became law in May 2025.[62]

The EGR policy provides Indiana's regulated electric utilities with an opportunity for expedited planning and procurement when load growth exceeds either (1) prior peak demand (by certain metrics), or (2) 150 MW. Approved EGR plans allow utilities to take requisite resource actions and earn cost recovery of generating projects for which need is demonstrated under the EGR plan. Already Indiana Michigan Power Company ("I&M"), which last filed an IRP in March 2025, is utilizing the EGR process to meet its 3,500 MW capacity commitment to new large customers.[63] Importantly, I&M cites <u>executed electric service agreements</u> behind its capacity commitments to support the load forecast in its petition.[64]

CGA urges the IURC to verify that AES Indiana's large load forecast is reinforced by firm contractual commitments between the Utility and any large customers before providing regulatory

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[58] CRA. "Utility planning best practices," pp. 15-16. *See* MO PSC Docket No. EO-2026-0088, "Annual IRP update: Appendix A".

[59] Energy Futures Group. "Review of large load tariffs to identify safeguards and protections for existing ratepayers," pp. 28-29.

[60] Colorado PUC. Proceeding No. 24A-0442E. *In the matter of the application of Public Service Company of Colorado for approval of its 2024 Just Transition Solicitation*. See Decision No. C25-0747. (Issued November 6, 2025.) See 63 at pp. 28-29 and 101 at pp. 44-45

[61] *See* 170 Indiana Administrative Code ("IAC") Chapter 4, Rule 7, "Guidelines for IRP by an electric utility". In particular, see 170 IAC 4-7-2.5, "Effects of IRP in docketed proceedings".

[62] Indiana Public Law 217 (2025), formerly House Bill 1007, "An act to amend the Indiana Code concerning utilities," was added as a new chapter to Ind. Code 8-1-7.9.

[63] *See* Indiana Utility Regulatory Commission ("IURC"). Docket No. 46301. *In the matter of the verified petition of Indiana Michigan Power Company for approval of an Expedited Generation Resource Plan, associated accounting and ratemaking relief (including authority to defer costs for subsequent recovery and timely recovery of costs), a Generation Resource Submittal compliance filing process, and protection of confidential information from public disclosure.* (Filed September 26, 2025.)

[64] IURC. Docket No. 46301. Verified Petition at 24 (p. 9) and 26 (p. 10).

pathways to approval of any associated projects. Our recommendations are discussed in detail in Section V(B) below.

V. RECOMMENDATIONS

CGA offers several recommendations that could guide the Utility's Short-Term Action Plan, inform future IRP processes, and ensure ratepayer protections as AES seeks to provide reliable electric service at least-cost. We encourage the IURC to urge AES to make the following improvements.

A. ***Modeling inputs & assumptions.*** Before proceeding with resource actions under the 2025 IRP Preferred Portfolios, with implementation of the Short-Term Action Plan, or with development of the next IRP, AES should:

1. **Re-model higher natural gas prices in the Reference Case.** AES should model an Updated Reference Case scenario using gas prices on par with those in the Gas Infrastructure Challenges scenario and should also apply a sensitivity to the Updated Reference Case with federal tax credits for wind and solar reinstated in the early 2030s.

2. **Assume capital costs for CCGTs, simply-cycle turbines, and RICE units remain high through the end of the decade.** AES should reevaluate the 2032 addition of the 700 MW CCGT under the Reference Case, Mid Data Center Load scenario in its next IRP, comparing whether new thermal generation is prudent based on the capital cost outlook for storage, solar, wind, and thermal resources at that time. Also see recommendations under Section V(B), noting items (B)(1) and (B)(3) in particular.

3. **Expand the pool of energy storage technologies considered "commercially viable."**
    - **a.** Before proceeding with resource actions under the 2025 IRP, AES should re-run the Reference Case model making long-duration, multi-day, and non-lithium-ion energy storage selectable resources starting in 2028.[65]
    - **b.** AES should also assume the domestic manufacturing and supply chain will grow such that American-made energy storage systems adhering to the Prohibited Foreign Entity ("PFE") standards established in the OBBBA and eligible for federal subsidies will meet demand within the near-term horizon of this IRP.[66] The storage

[65] In 2023 CRA recommended utilities begin building a knowledge base around LDES technologies by integrating them into IRP, and ESIG recommends "addressing technology head-on" in scenario-based planning processes by comparing scenarios built around futures with divergent technological realities. *See* CRA, "LDES: Leading indicators," and ESIG, "From goals to plans: Improving rigor, transparency, and decision-making in electricity plans with ambitious policy targets," (October 2025), accessed at: https://www.esig.energy/wp-content/uploads/2025/10/ESIG-Plannning-for-Ambitious-Targets-report-2025.pdf. *Also see* Form Energy. "Form Factory 1." (December 23, 2025.) Accessed at: https://formenergy.com/form-factory-1/.

[66] Solar Power World. "Almost overnight, the US is on way to having an oversupply of ESS battery cells." (January 5, 2026.) Accessed at: https://www.solarpowerworldonline.com/2026/01/almost-overnight-the-us-became-an-oversupply-market-for-ess-battery-cells/. *Also see* Wood MacKenzie. "2026 Outlook. Energy storage: 5 trends to

industry is expected to realize year-over-year domestic growth in both production and deployment starting in 2028.[67] Thus, in developing the next IRP, AES should continue using publicly available and RFP-informed cost data, accounting for all available tax credits and adders.[68]

4. **Model transmission opportunities and benefits made possible by MISO LRTP Tranches 1 and 2.1.** AES should evaluate whether LRTP will enable deferred or avoided investment in new generation by modeling the impact of completed projects in its next IRP.

5. **Model the Reference Case using MISO indicative DLOL values for future wind resources.** AES should then re-evaluate whether investment in wind will contribute to a least-cost, reliable portfolio before proceeding with resource actions in the 2025 IRP.

B. Large loads. To meet its imperative under the regulatory compact to both serve the public interest and provide non-discriminatory service to new customers, AES should:

1. **Withdraw actions associated with the Reference Case, Mid Data Center Load from the Short-Term Action Plan.** AES should evaluate whether additional generating and/or storage resources beyond those included in the Reference Case, No Data Center Load are required, and subsequently determine whether an EGR Plan, upcoming IRP, or other regulatory avenue is most appropriate to obtain necessary project approvals, <u>at the time of contracting with</u> any large load customer(s).

2. **File a large load tariff with the IURC prior to the submission of its 2028 IRP.** AES should incorporate in such a tariff utility best practices, consumer protections, and demand response and clean energy incentives (e.g., voluntary programs or interconnection prioritization).

3. **Perform additional diligence on the feasibility of meeting large loads with wind, solar, and energy storage**. As large load customers are contracted, AES should conduct subsequent all-source RFPs to identify resources with attributes consistent with those required to serve the large loads rather than prematurely ascribing resources to uncommitted customers.

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look for in 2026." (January 26, 2026). Accessed at: https://www.woodmac.com/news/opinion/energy-storage-2026-outlook/

[67] *See* Wood MacKenzie Power & Renewables and American Clean Power Association ("ACP"). "US Energy Storage Monitor: Q4 2025 report." (Published December 2025.) Accessed at: go.woodmac.com/l/131501/2025-12-03/35531g/131501/17658352096JvlrzEg/US_ESM_Q4_2025_ES.pdf. *Also see* ACP. "U.S. energy storage industry to invest $100 billion in American grid batteries." (April 29, 2025.) Accessed at: https://cleanpower.org/news/energy-storage-industry-commits-100-billion-for-american-grid-batteries/

[68] Beyond access to the ITC through 2026, energy storage systems may also qualify for federal tax credit adders available to projects located in energy communities or that utilize domestically produced components (in addition to meeting PFE requirements).

4. **Exclude uncommitted large loads from future IRP load forecasts.** AES should only include in the IRP load forecast those loads for which an ESA and IA have been executed.

C. Other. In implementing the Short-Term Action Plan, AES should undertake the following:

1. **Improve the All-source RFP requirements to elicit robust, diverse proposals.**

   a. AES should offer respondents the option of availability guarantees in lieu of production guarantees in order to both maintain consistency with widespread practice and encourage a greater number and variety of proposals.

   b. Particularly as pertinent to the relatively wide-ranging and diverse asset class of "storage" technologies, AES should not dictate in future All-source RFPs whether storage proposals should be from short-duration and long-duration technologies. Rather, storage proposals should be evaluated equally against the goals of the procurement and their ability to resolve gaps in the AES system.

2. **Pilot long-duration, multi-day, and non-lithium-ion storage technologies for some portion of the 40 MW of storage included in the Short-Term Action Plan.** AES should review responses from the 2024 RFP for possible long-duration, multi-day, and non-lithium-ion storage pilot or demonstration projects and consider working with those developers to establish such collaborations and include in future RFPs opportunities for possible program proposals.

VI. CONCLUSION

CGA thanks the IURC for the opportunity to express our concerns and offer our recommendations in the matter of the AES Indiana 2025 IRP. We look forward to feedback from the Commission, AES, and other stakeholders on these and other issues related to this IRP.

Sincerely,

Emily Piontek, Regulatory Associate
Clean Grid Alliance