Comments on the AES Indiana 2025 Integrated Resource Plan

Citizens Action Coalition, Solar United Neighbors, Vote Solar

Prepared by Energy Futures Group (EFG)

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INTRODUCTION

We appreciate the collaborative stakeholder process AES IN led while crafting its 2025 IRP and recognize that the dynamics driving this year's plan have shifted substantially. However, we have substantial concerns, detailed below, about AES IN's process and evaluation of portfolios and the large load scenarios, including the use of a rudimentary analysis by AES IN in the media to make unverified and premature claims about the potential impacts of data centers. There are also opportunities for improvement in transmission planning, demand response, and energy efficiency.

The insufficient process and evaluation should increase scrutiny of the IRP's overall findings. Of note, AES IN's preferred portfolios did not include a single MW of additional solar or wind for the 20-year duration of the planning horizon. Further, the preferred portfolio relies on the substantial addition of natural gas power plants – and enormous increase in carbon emissions – under the Mid DC Load preferred portfolio, driven by a speculative large load forecast. Ultimately, AES IN should not compromise the affordability, environmental sustainability, reliability, stability, and resiliency of our grid to accommodate data center load growth.

RECOMMENDATIONS

Section 1: Process & Evaluation

- AES IN should realign the IRP scorecard with Indiana's five pillars of electric service by putting greater weight on reliability, resiliency, stability and environmental sustainability and moderating the emphasis on utility cost risk.
- AES IN should include reliability metrics from the Quanta report in its scorecard, as in previous IRPS.
- AES IN should not use "total installed dispatchable capacity" or "total firm dispatchable capacity" as metrics to measure reliability, resilience, or stability.
- AES IN should discontinue using carbon intensity in all future IRPs. This metric should be disregarded when evaluating AES IN's 2025 IRP.
- AES IN should employ a robust and rigorous scoring approach established at the beginning of the process and using industry-standard metrics.

Section 2: Large Load Scenarios

- AES IN should not use the rate analysis presented in any future publications or press releases, and it should be disregarded when evaluating AES IN's 2025 IRP.
- AES IN should run an informative rate analysis: Calculate average cost to residential and commercial rate classes assuming the use of a separate data

center rate class and associated tariff. Assume (and transparently identify) a cost allocation factor for new data center customers and assess costs to existing rate classes with and without data center customers.

- AES IN should rely on a standard PVRR assessment: Compare scenarios based on total annual revenue requirement.
- AES IN should provide clear and transparent evidence that the selected preferred portfolio data center load forecast is based on actual committed load.
- The Commission should ensure that any future new builds justified by this IRP demonstrate the existence of sufficient protection for residential ratepayers codified in the contract and/or tariff when they come in front of the Commission for approval.

Section 3: Transmission Planning

- AES IN should clarify whether analyses supporting the modeled portfolios extend beyond steady-state power flow to include dynamic stability, sub-synchronous resonance (SSR), or electromagnetic transient (EMT) analysis. If assessed, AES IN should provide evidence of these analyses.
- AES IN should provide evidence of planning to meet impending MISO requirements that reflect operational security considerations and indicate how new large load customers would meet system standards.

Sections 4.1 & 4.2: Market Potential Study & Energy Efficiency (EE)

- AES IN should run the residential behavioral bundle as an independently selectable resource using cost assumptions informed by recent actual program results.
- AES IN should establish the residential tier cost threshold in collaboration with stakeholders.
- AES IN should revise its EE levelized cost methodology by discounting physical savings using a real discount rate (or, equivalently, by consistently discounting both costs and benefits in real terms).
- AES IN should: (1) incorporate ERAP, at least for C&I, as a selectable option in the primary candidate portfolio set evaluated under the scorecard; and (2), report the ERAP selection results (including savings, costs, and bundle composition by vintage and sector), rather than relegating it to a sensitivity analysis.

Section 4.3: Demand Response (DR)

- AES IN must develop a robust strategy for co-deployment of its energy programs, including EE, DR, time varying rates (TVRs), and distributed energy resources (DERs).
- AES IN should develop a strategy specific to each EE program offering to (1) demonstrate how marketing and delivery can achieve goals of increased enablement of devices and technologies, (2) embed offerings for DR/TVR/DER enrollment at optimal touch points, and (3) achieve more successful development of load flexibility programs through higher adoption rates and improved cost effectiveness.
- AES IN should develop eligibility guidelines for its complementary flexible load programs that encourage co-enrollment, thereby providing the most cost-effective opportunities to scale its DR resources. AES IN should work with its Demand Side Management (DSM) Oversight Board (OSB) to identify a comprehensive list of complementary programs and ensure that any barriers to co-enrollment are considered and potentially addressed.
- AES IN should work with its OSB to determine the optimal rate design characteristics and strategies for deployment of its TVR programs, including time-of-use (TOU) rates, which should leverage other EE/DR participation in addition to customer-facing tools and efficient targeting strategies.
- AES IN should conduct a new line loss study (or adapt their existing study) to estimate both average marginal and peak marginal line loss values for applications for energy efficiency and demand response resources, respectively, before the next planning study or litigated DSM plan case.

1. PROCESS & EVALUATION

1.1 Scorecard Approach & Selected Metrics

AES Indiana utilizes a "scorecard" evaluation approach to assess performance between portfolios and scenarios using key performance indicators across four categories: (1) Affordability; (2) Reliability, Resiliency & Stability; (3) Risk and Opportunity; and (4) Environmental.

AES IN claims that its key performance indicators are designed to be consistent with the "Five Pillars of Electric Service" identified in Indiana Code.[1] Upon review, the scorecard does not appear aligned with those pillars in any measurable way.

TABLE 1. Indiana Five Pillars of Electric Service Represented in AES IN 2025 IRP Scorecard[2]

Indiana Pillars	Included in Scorecard
Reliability	**None**
Affordability*	10-Year Levelized Supply Cost (2026$/MWh) 25-Year Supply Cost (2026$/MWh) 10-Year PVRR 25-Year PVRR
Resiliency	**None**
Stability	**None**
Environmental Sustainability	Total CO_2 Emissions (Million Tons) Carbon Intensity (lb/MWh)

*As discussed in the section on Misleading Revenue Analysis, these alone do not indicate affordability in the absence of a ratemaking assessment.

AES IN's initial scorecard approach, as presented in its second Public Stakeholder Meeting, better aligned with the above categories.[3] Unfortunately, in the subsequent months, AES IN revised the scorecard metrics, distancing themselves from the five pillars, with no further discussion with or information provided to stakeholders.

[1] IN Code § 8-1-2-0.6 (2025).
[2] AES IN 2025 IRP, Volume 1, p. 217.
[3] AES IN 2025 IRP, Public Advisory Meeting #2, July 24, 2025, p. 95.

AES IN employs the metrics "reliance on external markets" and "dispatchable capacity" for "reliability, resiliency and stability" in its scorecard, even though these are not standard metrics for assessing reliability, resiliency, or stability. While AES IN directly recognizes this,[4] it excuses the lack of meaningful metrics simply because "by design, the portfolios meet MISO's capacity requirements."[5]

AES IN did not even rely on the commissioned Quanta Technology assessment, which provided reliability analyses and scenario assessment using traditional metrics, as they have for previous IRPs.[6] That assessment found no impacts under any scenario if AES IN maintains import capability. In an extreme scenario if AES were to become fully islanded, Quanta found impacts for all scenarios in the mid- and high-data center load cases, particularly for the High Environmental portfolio. (See **FIGURE 1. AES IN 2025 IRP Figure** But, again, **this entire Quanta assessment was not reflected at all in the scorecard.**

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[4] "AES Indiana hired Quanta to perform additional modeling related to reliability, resiliency and stability metrics. This analysis provides additional support for the IRP, but the metrics are not included in the scorecard." AES 2025 IRP, Volume 1, p. 157.

[5] *Id*., p. 230. In fact, though the portfolios meet MISO's capacity requirements, even that does not ensure an ability to access such capacity. A measure of annual capacity purchases over the next several years would have been an additional useful metric to assess ability to meet capacity needs.

[6] *Id*., p. 238.

FIGURE 1. AES IN 2025 IRP Figure 9-108: Quanta Study – No Import Lost Load (2035)

	Import 0% (2035)					
	LOLE	EUE	LOLP	LOLH	LOLH (Summer)	LOLH (Winter)
Reference Case - No Data Center	0	0	0.0%	0	0	0
Reference Case - Low Data Center	0	0	0.0%	0	0	0
Reference Case - Mid Data Center	12	1	0.2%	14	8	0
Reference Case - High Data Center	10	1	0.1%	13	4	0
Gas Infrastructure Challenges - No Data Center	0	0	0.0%	0	0	0
Gas Infrastructure Challenges - Low Data Center	0	0	0.0%	0	0	0
Gas Infrastructure Challenges - Mid Data Center	0	0	0.0%	0	0	0
Gas Infrastructure Challenges - High Data Center	0	0	0.0%	0	0	0
High Environmental - No Data Center	0	0	0.0%	0	0	0
High Environmental - Low Data Center	1	0	0.0%	1	0	0
High Environmental - Mid Data Center	1996	999	32.6%	2,857	914	722
High Environmental - High Data Center	3322	4770	70.9%	6,213	1,819	1,318
Stable Markets - No Data Center	0	0	0.0%	0	0	0
Stable Markets - Low Data Center	0	0	0.0%	0	0	0
Stable Markets - Mid Data Center	290	61	5.7%	503	147	80
Stable Markets - High Data Center	357	89	6.8%	594	173	1

Instead, the scorecard focuses largely on cost and portfolio risks to the utility, as demonstrated by the set of additional metrics listed in **TABLE 2**.

TABLE 2. Other Metrics Represented in AES Indiana 2025 IRP Scorecard[7]

Portfolio Attributes	Other Metrics Included in Scorecard
Reliance on External Markets	Market Purchase + Sales (%) 25-Year Energy Purchases, % of Load 25-Year Energy Sales, % of Load
Dispatchable Capacity	Dispatchable Capacity, Percent of Peak (2035) (%) Dispatchable Firm Capacity, Percent of Peak (2035) (%)
Cost Risk	Opportunity (Mean – P5) Risk (P95-Mean) Environmental Scenario Risk (2026$MM) Average % Difference from Optimal

[7] AES IN 2025 IRP, Volume 1, p. 217.

Recommendation: If AES IN were to align its scorecard with the five pillars of electric service, it would look substantially different, with greater weight on system performance and environmental sustainability and less emphasis on utility cost risk. Critically, it would also include reliability metrics from the Quanta report in its scorecard.

Carbon Intensity as a Metric

Finally, regarding environmental sustainability, we were disappointed that AES IN disregarded our recommendation to eliminate the carbon intensity (CO_2/MWh) metric. Carbon intensity is completely unrelated to environmental sustainability and has been criticized for decades by subject matter experts for being a metric used for greenwashing. Environmental impacts are related to the absolute quantity of emissions, not their rate, which is why we support the use of the total CO_2 emissions metric in the scorecard. The carbon intensity metric provides a highly misleading evaluation of environmental sustainability that leads to erroneous conclusions. For example, total emissions can increase – resulting in greater environmental harm – at the same time carbon intensity is decreasing when there is load growth.

Recommendation: AES IN should discontinue using carbon intensity in all future IRPs, and this metric should be disregarded when evaluating AES IN's 2025 IRP.

1.2 Scorecard Format & "Scoring"

AES Indiana's scorecard does not follow logical "scoring" practices beyond the basic items included in the scorecard, nor does it use appropriate visual cues. Instead, AES IN applied default Microsoft conditional formatting rules across each column in its scorecard, creating the perception that each metric is equal, should be assessed by the same standard (red to green), and that values should be compared across load scenarios. Below, we outline why each of those steps is problematic.

Equal weight for each metric

This scorecard incorrectly indicates that AES Indiana treats each presented metric as equally important. Yet, there are multiple cases where metrics presented overlap, thus inflating their relative importance. For example, there are four columns indicating "affordability." However, the relative value of each "affordability" metric is the same for each scenario. The additional metrics do not provide additional explanatory value. Rather, they falsely indicate greater weight for those metrics than for others (for example, "environmental" has only two metrics, and reliability/resilience/stability arguably have none). If affordability is indeed the primary concern, AES IN could express its importance by using multiple metrics with meaningful differences, e.g., PVRR versus scenario bill impacts on residential customers.

Use of default Microsoft conditional color formatting

It appears that AES IN applied the same conditional formatting settings to each column. This results in a scorecard that is, at best, unusable due to its lack of clarity and, at worst, misleading about the scale of differences between values. There is no key provided, which leads the reader to simply assume that red values are "bad" and green values are "good." Appropriate evaluation would assign a "score" for each metric, with consideration for the actual metric and what it indicates.

FIGURE 2. No Data Center Scenario Color Coded Metrics for Dispatchable Capacity

, AND STABILITY	
Dispatchable Capacity, Percent of Peak (2035)	Dispatchabl FIRM Capacity , Percent of Peak (2035
%	%
111%	90%
111%	90%
111%	91%
111%	90%

AES IN's highly simplified approach risks painting over critical tipping points in metrics (for example, at what PVRR do existing customers see untenable rate increases?) and does not assist in the comparative evaluation of scenarios (for example, are any of these scenarios significantly different in terms of resilience risk?).

It also results in color coding virtually identical metrics as different, showing a difference when there is none. For example, metrics for Dispatchable Capacity showed bright red color coding for portfolios with 90% dispatchable firm capacity (% of 2035 peak demand), and green for a portfolio with 91% dispatchable firm capacity, suggesting a meaningful difference between these portfolios on this metric when there actually is none (**FIGURE 2**).

Lack of comparison across load forecasts

While it is appropriate to compare the scenarios within the context of each individual load forecast, the scorecard fails to illustrate the primary driver behind the differences among the 16 scenarios: data center load growth. For example, the color scaling for 25-Year PVRR shows the High Regulatory scenario as red across all scenarios. While it is certainly the case that PVRR for that scenario is substantially higher relative to the others, the coloring within Data Center Cases obscures the critical role that different load forecasts play. As shown in **FIGURE 3** below, if the same color scale is applied across all cases and scenarios, it becomes clear that, while the High Regulatory scenario remains the highest cost, **the driving force is the amount of new load coming online.**

FIGURE 3. AES IN 2025 IRP Scorecard Original PVRR Column vs. Recolored Column to Demonstrate Differences across all Data Center Cases

		Affordability		
Data Center Case	Portfolio	25-Year PVRR (2026$MM, 2026-2050) **ORIGINAL COLOR:** Across each Data Center Case		25-Year PVRR (2026$MM, 2026-2050) **RE-COLOR:** Across all cases
No Data Center Load	Reference Case	$10,092		$10,092
	Gas Infrastructure Challenges	$10,161		$10,161
	High Regulatory: Environmental	$15,455		$15,455
	Stable Markets Scenario	$10,070		$10,070
Low Data Center	Reference Case	$12,654		$12,654
	Gas Infrastructure Challenges	$13,047		$13,047
	High Regulatory: Environmental	$19,827		$19,827
	Stable Markets Scenario	$12,699		$12,699
Mid Data Center	Reference Case	$18,187		$18,187
	Gas Infrastructure Challenges	$18,499		$18,499
	High Regulatory: Environmental	$30,040		$30,040
	Stable Markets Scenario	$18,266		$18,266
High Data Center	Reference Case	$23,754		$23,754
	Gas Infrastructure Challenges	$24,032		$24,032
	High Regulatory: Environmental	$37,871		$37,871
	Stable Markets Scenario	$23,990		$23,990

Similarly, total CO_2 emissions are approximately 50-100% higher under high load growth versus no load growth cases, underscoring the significant negative impact of data center load growth on environmental sustainability, which is concealed by this visual.

FOCUS ON: Dispatchable Capacity as "Reliability"

AES Indiana uses two metrics as indicators of a portfolio's ability to provide reliability, resiliency, and stability: "total installed dispatchable capacity" (defined as all storage and gas resources) and "total firm dispatchable capacity" (defined as the accredited value of storage and gas resources). This is not a standard metric for assessing system reliability, resilience, or stability. While gas and storage resources are generally able to respond quickly to changing grid conditions, their mere existence does not, in itself, confer system reliability, resiliency, or stability. Reliability can and should be measured using standard metrics for such. As previously discussed, AES IN hired Quanta Technologies precisely to assess these particular metrics. The metrics that Quanta assessed that better reflect system reliability include loss-of-load expectation (LOLE), expected unserved energy (EUE), loss-of-load probability (LOLP), and loss-of-load hours (LOLH) both annually and seasonally. Notably, in Quanta's assessment, none of the scenarios projected reliability issues. When they ran the extreme case of the AES IN system being islanded, the major difference in reliability was not between the portfolios with and without "dispatchable capacity," but rather between the different load scenarios. **The risk that AES IN and Quanta's actual reliability assessment identified is the integration of substantial new data center load, not the amount of storage and gas resources in AES IN's portfolio.**

1.3 Non-Functional Scorecard Undermines Assumption Development

AES Indiana's insufficient scorecard places too much weight on cost metrics, ignores the dominant role of data center-related load growth, and obscures critical assumptions that merit targeted analysis, whether via sensitivities or inclusion in scenarios. Several inputs warrant deeper scrutiny. For example, AES IN applies the same energy market price and fuel price assumptions across all scenarios regardless of load forecast, which does not reflect a realistic future assumption. Higher load levels typically increase upward pressure on market prices and exposure to fuel price volatility. Given AES IN's shift toward more gas capacity, the impacts of fuel cost risk could be substantial. In that context, static gas price assumptions are increasingly unrealistic.

Recommendation: AES IN should employ a robust and rigorous scoring approach established at the beginning of the process and using industry-standard metrics. This would better support modeling assumption development to assess scenarios that truly meet system priorities. AES IN should rectify this before pursuing new generation.

1.4 Preferred Resource Portfolio Selection

AES Indiana's defense of its preferred scenario is limited in scope, overly focused on cost metrics that substantially overlap, and unsupported by the purported scorecard analysis. In summary:

"Affordability": AES IN conflates lower PVRR and lower average rate with affordability, which AES IN even emphasized is inappropriate (discussed in detail below).

Reliability Analysis: All portfolios meet reliability metrics assessed by Quanta, except the High Regulatory Case. The Quanta analysis should be reflected in the scorecard.

Emission Impacts: AES IN states that the Reference Case portfolios have similar carbon emission impacts to the Gas Infrastructure Challenges and Stable Markets Scenarios, glossing over the comparison to the High Regulatory Case portfolio. In fact, these cases see twice the carbon emissions compared to the High Regulatory Case, even in the lowest load scenario. In the mid-data center case, the difference between the High Regulatory Case and the Reference Case (preferred) is 47 million metric tons of CO_2, or the equivalent of more than twelve coal-fired power plants operating for a full year.[8]

Load Growth: This scorecard fails to quantify or illustrate the clearest driver in differences across all metrics: data center load growth.

Large Customer Clean Energy Preferences: AES Indiana did not consider large load customer preferences for sustainable sources of generation in its scenarios, which could have been represented under the Environmental Sustainability pillar. For example, AES IN's preferred portfolio for its mid-data center load growth case relies primarily on natural gas additions. However, this would directly conflict with Google's sustainability commitment to achieve 100% carbon-free energy by 2030.[9] This omission of sustainability considerations is concerning, given Google is developing a 1,200 MW data center in AES IN's service territory and could make up the vast majority of load growth.

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[8] EPA Greenhouse Gas Equivalencies Calculator, available at https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator
[9] Google Environmental Report, 2025, available at, https://www.gstatic.com/gumdrop/sustainability/google-2025-environmental-report.pdf

2. LARGE LOAD SCENARIOS

2.1 Misleading Revenue Analysis

AES Indiana writes that, historically, PVRR has been the "best practice for cost metric in IRPs," emphasizing that it provides a holistic cost metric that captures all capital, operating, and market costs across different portfolios.[10] It is true that PVRR has long been used as one metric for assessing system cost impacts. However, in both its public stakeholder meeting and in the final IRP, AES IN was careful to emphasize that **the PVRR rate analysis performed is system-level and is <u>not</u> "a precise forecast of current or future rates for AES Indiana, nor does it represent actual rate impact for existing or new customers**."[11] Even with these caveats in place, AES IN uses average cost across the IRP to represent "affordability" – implying that a lower average means lower customer rates.

Further, on September 19th, 2025, AES Indiana released a press release titled "Supporting Growth in Central Indiana with Transparency and Commitment." In this press release, in direct reference to the IRP PVRR assessment, AES President Brandi Davis-Handy wrote "we've developed a strategy that shows no negative impact to existing customer rates should AES Indiana power data centers in the future." The release goes on to state that this is because the cost of additional investments to serve those customers will be spread over a larger amount of electricity sold, and that the information was "validated" in their most recent IRP public stakeholder meeting.

But during the meeting in question, AES IN verbally stated that the analysis would not be used to justify specific rate impact claims. This was also the first time the analysis had been presented to stakeholders and without a usable version of the workbook to review. Indeed, the IRP itself states that "the system cost metric is not a perfect representation of how cost allocation would occur [given a large load addition] and that a full cost-of service or similar cost allocation study would be required to analyze the cost impacts by customer class comprehensively."

AES Indiana's "Affordability" analysis, as presented in this IRP, raises three key issues:

1) AES IN has already used the analysis to make claims that additional investment required to support new large load customers will lower customer rates. This is not verifiable, as stated by the utility itself in the IRP and accompanying public meetings.

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[10] AES IN 2025 IRP Volume 1, p. 152.
[11] *Id*., p. 153.

2) The PVRR analysis is not a substitute for a specific plan to allocate costs to different rate classes, rather it assumes costs are spread across all MWhs sold. AES IN cannot claim to understand impacts on existing customers until the Commission approves how existing and future costs will be spread across rate classes.
3) The average PVRR analysis makes quantitative generalizations that call into question the legitimacy of the entire exercise.

Revenue Requirement Analysis

In Figure 9-87, AES IN shows the projected annual revenue requirement (in nominal $/MWh) of each scenario through the modeling period. It demonstrates that, indeed, when one divides the projected total revenue requirement ($MM) by the total system level sales (GWh), the highest load case yields a lower annual revenue requirement (nom$/MWh). **One key issue with this seemingly straightforward assessment, however, is AES Indiana's assumption that data centers will pay for both going forward <u>and</u> already incurred costs.** Data center customers may be assigned some of the existing transmission rate base costs which, across all scenarios, are assumed to be [redacted], adjusted for inflation.[12] However, it is not clear what portion of those costs new large customers will bear, a point that AES IN confirmed in Technical Meeting #4.[13]

AES IN includes new transmission costs associated with each of the data center scenarios. However, it is unclear whether all transmission costs associated with the new large load customers are fully accounted for, and AES IN's revenue requirement analysis does not show any intention of assigning overall system costs to new customers. For example, system costs could be disproportionately borne by existing customers even as new customers come online.

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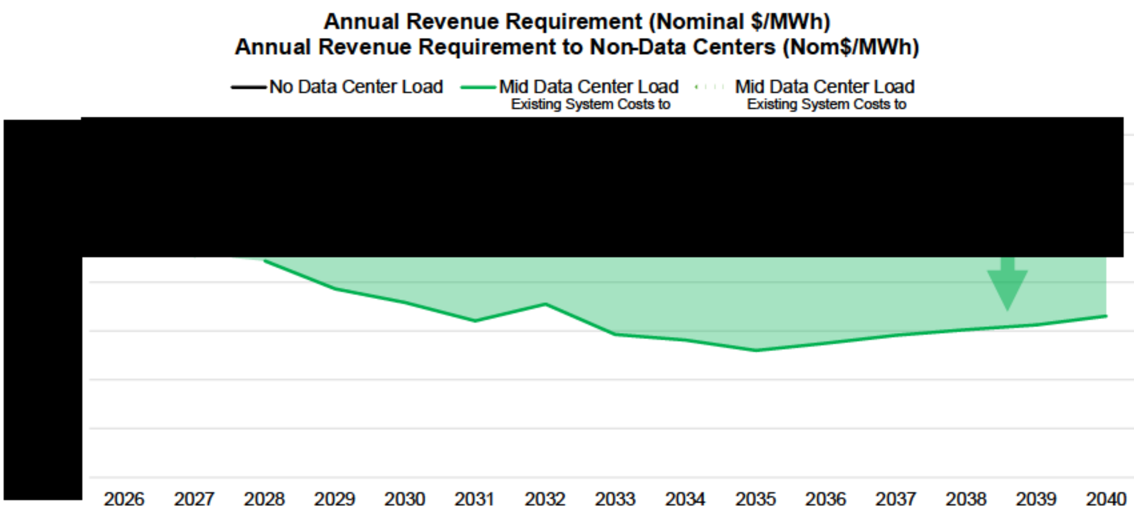
12 [redacted]
13 AES IN 2025 IRP, Technical Meeting #4.

CONFIDENTIAL TABLE 3. Revenue Requirement Assessment: All Existing System Costs Apportioned to All Customers vs. All Existing System Costs Apportioned to Existing Customers Only

[redacted]

The removal of existing system costs from the analysis, as demonstrated above, calls into question the major thrust of AES Indiana's argument – that there will be "no negative impact to existing customer rates". **FIGURE 4** shows the results of the calculation demonstrated in **CONFIDENTIAL TABLE 3** above across all years. Critically, this shows that simply by removing the certainty that existing system costs will be proportionally borne by new large load customers, the $/MWh impact range is effectively rendered null by 2040. Thus, the claimed "benefit" of large-load deployment is erased.

FIGURE 4. Range of Possible Annual Revenue Requirement Outcomes



As demonstrated, AES IN's back-of-the-envelope assessment is insufficient to ensure that the risk of negative rate impacts is mitigated without a full cost-of-service analysis. At the very least, we recommend that AES IN revisit this analysis to better reflect the differences in how large load deployment will affect different customer classes. We do recognize that cost assessments are a critical element of the IRP process and, as such, provide the following recommendations.

Recommendations:

- **Run a rate analysis:** Calculate average cost to residential and commercial rate classes assuming the use of a separate data center rate class and associated tariff. Assume (and transparently identify) a cost allocation factor for new data center customers and assess costs to existing rate classes with and without data center customers.
- **Rely on standard PVRR assessment:** Compare scenarios based on total annual revenue requirement. Ultimately, the full capital expense is the more critical metric to assess rather than $/MWh.

2.2 Speculative Large Load Scenario

As we expressed throughout the stakeholder process, AES Indiana's approach to modeling data center load scenarios represents an array of potential futures. We submitted comments stating that if the utility chose one of these forecasts as the "preferred" scenario, AES IN should provide clear and transparent evidence that such a forecast is based on actual committed load.

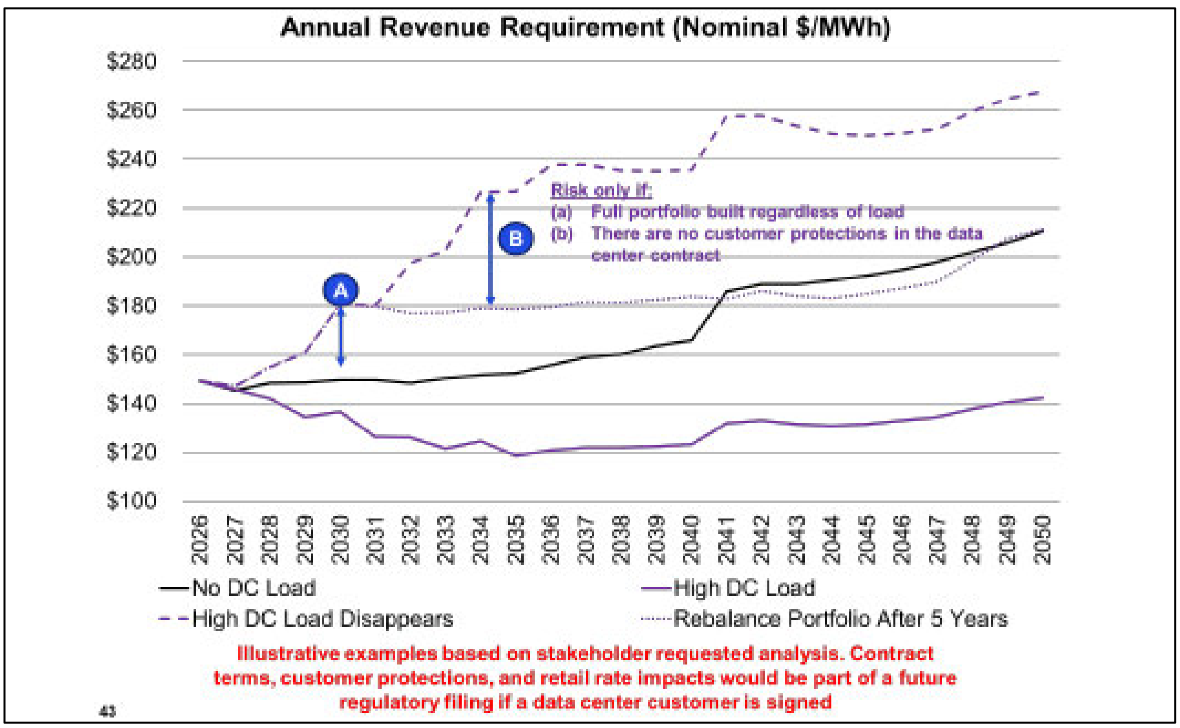
While we were happy to see AES IN take stakeholder feedback and jointly select the No Large Load and Mid-Data Center Load scenarios as "preferred," the above-requested material was not provided.

To date, no detailed information about anticipated large load customers, including size, location, and project stage, has been provided. As we have previously stated, planning for new generation build-out based on a speculative load forecast is not an appropriate approach to resource planning and is not in the best interest of AES IN customers.

2.3 Data Center Leaves Sensitivity

Responsive to stakeholder feedback, AES IN modeled two sensitivities related to data centers that do not materialize. The risk of stranded assets is one of the largest uncertainties AES IN faces as it considers new large load customer needs. AES IN did not provide much information related to these sensitivities, but did provide the same $/MWh revenue requirement analysis outlined above.

FIGURE 5. 9-129 Data Center Leaves Sensitivity (Annual Revenue Requirement)



In contextualizing this analysis, AES Indiana emphasizes that this is “an extreme scenario that has no customer protections in place at the time of investment” and that it can be used to “support the development of key customer protections and prudent capital investment planning.” However, there is no assurance of this, and no requirement that AES IN will build in the appropriate customer protections. **The status quo under AES IN’s existing rates and tariffs is that none of these ratepayer protections and assurances on large load customer cost recovery currently exist.**

Will AES IN allow stakeholders to be engaged in cost recovery related to these customers? What protections will be publicized? Evidence from other jurisdictions does not yet indicate a standard approach. In some cases, contracts are highly detailed and include substantial protection in the case of cancellations. In others, contracts are very minimal, with no indication of protection. Meanwhile, AES IN has already submitted transmission projects for MISO MTEP Appendix A approval for 1,200 MW and 250 MW spot load growth, likely corresponding to Google (Monrovia) and Sabey (Decatur Township) data center projects.

Recommendation: Our strong recommendation is that, given this particularly salient issue, any future new builds justified by this IRP must demonstrate the existence of sufficient protection for residential ratepayers codified in the contract or tariff when they come in front of the Commission for approval. A lower PVRR does not, in and of itself, constitute a ratepayer protection.

3. TRANSMISSION PLANNING

3.1 Large Load Integration

AES IN’s 2025 IRP[14] introduces one portfolio excluding data center load and three Data Center Portfolios reflecting potential large-load growth of 500 MW (Low), 1,500 MW (Mid), and 2,500 MW (High). AES IN selects the No Data Center and Mid Data Center portfolios as its preferred portfolios. While the IRP evaluates these scenarios at a portfolio level, data center demand is modeled using simplified assumptions to represent large, highly concentrated loads. Specifically, the IRP models generic data center load ramps that increase linearly over time and assume a constant 90% load factor for base modeling runs, with a sensitivity case evaluating a 70% load factor. However, the IRP does not clearly describe how the dynamic operational characteristics of large data center loads themselves are represented in reliability studies, nor whether analyses such as sub-synchronous resonance (SSR) screening or electromagnetic

[14] AES IN 2025 IRP, Volume 1.

transient (EMT) analysis were considered. Additional information on these modeling assumptions would be useful in light of increasing industry attention to the reliability implications of large power-electronics-dominated resources and loads.

The "Practical Guidance and Considerations for Large Load Interconnections"[15] presentation given at the last IURC IRP Contemporary Issues conference highlights that large data center interconnections pose reliability challenges that cannot be adequately assessed using steady-state analysis alone. The presentation explains that large data center loads exhibit characteristics such as rapid ramping, uncertain and highly variable demand profiles, distinct ride-through behavior, and complex interactions with protection and control systems. These characteristics can materially affect system frequency response, voltage regulation, and generator performance, particularly during disturbances or rapid load changes, and therefore require study methodologies that explicitly capture time-dependent and dynamic system behavior.

The presentation further notes that insufficient modeling of large load such as data centers can contribute to adverse reliability outcomes, including degraded frequency response, voltage instability, increased generator cycling, transmission congestion, and power quality issues. It documents industry experience in which large blocks of data center load have disconnected unexpectedly, sometimes in the range of hundreds or thousands of megawatts, demonstrating how uncoordinated load protections and inadequate dynamic analysis can exacerbate system disturbances rather than mitigate them. These examples underscore the importance of understanding how large loads respond during abnormal system conditions, not merely how they appear in steady-state planning snapshots.

Consistent with this guidance, the North American Electric Reliability Corporation (NERC) has emphasized through its 2025 Level 2 Alert on Large Loads[16] that transmission planners should evaluate the dynamic and frequency-related impacts of large load interconnections. NERC has cautioned that traditional planning approaches may not fully capture risks associated with fast-changing, power-electronics-dominated loads, and has specifically identified the need to assess dynamic behavior,

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[15] Practical Guidance and Considerations for Large Load Interconnections, Elevate Energy Consulting and GridLab, available at, https://www.in.gov/iurc/files/4.-Practical-Guidance-and-Considerations-for-Large-Load-Interconnections.pdf
[16] NERC Alert Level 2 - Large Loads, available at https://www.nerc.com/globalassets/programs/bpsa/alerts/2025/nerc-alert-level-2--large-loads.pdf

oscillatory interactions including potential SSR, and the system impacts of rapid load ramping and tripping events.

In addition, discussion at the recent MISO Large Load Workshop[17] emphasized that the rapid growth of large, concentrated loads presents emerging operational security challenges that existing planning and operating practices may not fully address. MISO highlighted the need for new or enhanced reliability expectations for large load customers, including improved real-time visibility and telemetry, more accurate operational load forecasting, consideration of fast ramping and sudden load loss in reserve requirements, and clearer operational performance expectations during system disturbances. These discussions signal that MISO is moving toward a future standard for large load interconnection and operation that goes beyond traditional planning assumptions and steady-state analysis. AES IN's 2025 IRP does not indicate how they would consider future large load customer amidst such emerging operational expectations. This raises concerns that the IRP is not adequately planning for the operational requirements that MISO has indicated will be necessary to reliably integrate large loads.

The IRP also lacks sufficient detail on cost causation and ratepayer protection associated with large load integration. Although AES Indiana states that cost causation principles are important, the IRP does not provide detailed discussion of how network upgrade costs would be allocated between large load customers and existing ratepayers. This distinction is critical to ensure that existing customers do not subsidize facilities constructed for the exclusive benefit of a single large load.

Recommendations:

- AES IN should clarify whether analyses supporting the modeled portfolios extend beyond steady-state power flow to include dynamic stability, sub-synchronous resonance (SSR), or electromagnetic transient (EMT) analysis. If assessed, AES IN should provide evidence of these analyses.
- AES IN should provide evidence of planning to meet impending MISO requirements that reflect operational security considerations and indicate how new large load customers would meet system standards.

[17] MISO, Large Load Workshop Presentation, available at https://cdn.misoenergy.org/20260130 Large Load Workshop Presentation738349.pdf

4. DEMAND SIDE RESOURCES

4.1 Market Potential Study

AES Indiana's 2025 IRP relies on the Demand-Side Management (DSM) Market Potential Study (MPS), prepared by GDS, to quantify energy efficiency (EE) and demand response (DR) potential. Because the MPS is a key input for the IRP's demand-side resource screening and modeling, its methods, assumptions, and translation into IRP inputs must be transparent and aligned with how DSM is expected to be planned and delivered in practice.

4.1.1 Stakeholder Process and Collaboration

We appreciate that AES Indiana facilitated a structured stakeholder engagement process during MPS development. Between September 2024 to July 2025, AES Indiana held bi-weekly meetings with GDS and the MPS stakeholder group to share updates and gather feedback on key methodological issues.

While many stakeholder recommendations were incorporated into the MPS, some were not. Given that the MPS serves as the evidentiary foundation for determining reasonably available and achievable DSM, AES Indiana should provide a clearer account of: (a) which stakeholder recommendations were adopted, and which were not, and (b) how these decisions impacted the modeled achievable potential and costs used in the IRP.

4.1.2 Potential Scenarios (Including Enhanced RAP)

The AES Indiana MPS provided Technical, Economic, Maximum Achievable (MAP), and Realistic Achievable Potential (RAP) estimates. Additionally, at the request of stakeholders, GDS developed an Enhanced Realistic Achievable Potential (ERAP) scenario. The ERAP scenario adjusts incentive levels to increase participation beyond RAP levels, while still accounting for cost-effectiveness.

We support the inclusion of an enhanced scenario. It more accurately reflects real-world program planning, where administrators can increase savings through higher incentives, targeted delivery, and expanded trade ally engagement, especially in the C&I sector, provided it remains cost-effective. However, for the IRP to effectively utilize this scenario, it must be modeled as a selectable resource bundle and not merely as a sensitivity analysis. As discussed later, the AES Indiana IRP did not fully realize this objective.

4.2 Energy Efficiency (EE)

AES Indiana's 2025 IRP treats energy efficiency as a resource option informed by the MPS, represented by a limited number of EE bundles and time vintages, consistent with prior IRPs. We appreciate that AES IN and its consultants implemented a bundling structure that, at least partially, aligned with stakeholder recommendations.

4.2.1 EE Bundling Structure

While the EE bundling structure implemented by AES IN generally reflects stakeholder input, key implementation choices ultimately reduced EE selection.

AES IN modeled EE through sector and offering-based bundles (e.g., residential income-qualified, C&I, and two residential tiers) treating these bundles as selectable resources in capacity expansion.[18] This structure preserves major market and delivery distinctions and avoids aggregating disparate measures. This approach allows the model to select EE in a way that reflects actual programmatic tradeoffs (e.g., whether low-cost, high-uptake bundles are chosen over higher-cost bundles).

However, three implementation choices materially affected EE selection outcomes in ways that, in our view, bias results against EE and should have been corrected:

1. *The residential behavior bundle was not re-tested as a standalone bundle after cost corrections were applied.*

    In early model runs, AES Indiana's residential behavioral EE was not selected due to its higher cost. AES proposed combining the behavioral bundle with the lower-cost residential Tier 1 bundle. Simultaneously, we pointed out that AES IN's assumed program costs for behavioral EE were significantly higher than recent actual program results. While AES IN adjusted the behavioral cost assumptions, it did not re-run residential behavioral EE as a standalone bundle to determine if the corrected cost would allow it to be independently selected. Consequently, behavioral EE appears in the preferred portfolio only as part of a combined residential Tier 1 bundle, preventing stakeholders from understanding whether (and how much) behavioral EE is cost-effective on its own. Furthermore, the higher cost behavioral measures increased the overall cost of the residential Tier 1 bundle, although the bundle was ultimately selected.

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[18] Income-qualified bundles were "forced" in and were split into measures supported by AES IN and those by the Indiana Office of Energy Development.

Recommendation: AES IN should run the residential behavioral bundle as an independently selectable resource using cost assumptions informed by recent actual program results. AES Indiana should rectify this issue in advance of its upcoming DSM plan filing.

2. *The cost cut-off point between residential Tier 1 and Tier 2 was set too low, shifting measures into an unselected Tier 2.*

   AES Indiana used a $70/MWh (levelized) cut-off between residential Tier 1 (low/medium cost) and Tier 2 (high cost). We recommended a higher cutoff to retain more moderately cost-effective measures in Tier 1, which would have increased the Tier 1 savings potential. The lower cutoff forced a meaningful set of measures into Tier 2, which was not selected in the IRP preferred portfolio. Therefore, the cutoff decision effectively reduced achievable residential EE savings, not because the measures are necessarily uneconomic, but because they were placed into a bundle that the model did not select.

   Recommendation: AES IN should establish the residential tier cost threshold in collaboration with stakeholders. Initial modeling runs should be performed to evaluate the selection of the residential Tier 1 bundle and, if necessary, revise the cut-off threshold up or down accordingly. AES Indiana should rectify this issue in advance of its upcoming DSM plan filing.

3. *Applying a nominal discount rate to EE savings overstates levelized costs.*

   In levelized cost calculations for EE bundles, AES Indiana used a nominal discount rate, which includes inflation, to discount EE savings. Because physical energy savings do not inflate with general price levels as costs do, using a nominal rate to discount kWh savings undervalues the present value of these savings, thereby artificially inflating the $/MWh levelized costs for EE. While we raised this concern during the IRP EE bundling process, the final IRP did not address the issue.

   Correcting the discount rate improves (i.e., decreases) the levelized costs, as shown in **TABLE 4**. The EE levelized costs used in the AES IN IRP were overstated by as much as 17%.

TABLE 4. EE Bundle Levelized Costs: Modeled and Corrected

Scenario	Bundle	IRP $/MWh	Corrected $/MWh	% Error
RAP, Vintage 1	C&I	$19.95	$17.37	15%
RAP, Vintage 1	Res Tier 1	$46.26	$39.79	16%
RAP, Vintage 1	Res Tier 2	$113.29	$96.93	17%

This issue unfairly disadvantages EE in the IRP, where AES IN evaluates levelized cost metrics across portfolios and resources, and where EE selection can depend on relatively small differences in levelized costs.

Recommendation: AES IN should revise its EE levelized cost methodology by discounting physical savings using a real discount rate (or, equivalently, by consistently discounting both costs and benefits in real terms). AES Indiana should rectify this issue in advance of its upcoming DSM plan filing.

4.2.2 Enhanced RAP

In our 2022 IRP comments, we recommended that AES IN not treat RAP as the ceiling for EE modeling. We suggested higher achievable levels, up to MAP, or at least an optimized RAP/MAP blend, to be selectable within the IRP, particularly for cost-effective C&I opportunities.

During the 2025 IRP process, stakeholders again requested that Enhanced RAP (ERAP) EE bundles, especially for C&I, be modeled as selectable resources. AES IN ultimately conducted an ERAP sensitivity analysis using Reference Case capacity expansion runs across data center cases, which we appreciate. However, a sensitivity analysis is not a substitute for integrating ERAP into the actual portfolio decision set.

An IRP is intended to identify a least-cost, risk-balanced resource strategy under uncertainty. Excluding ERAP from the selectable resource set effectively predetermines the outcome in favor of supply-side alternatives. AES IN's own sensitivity results indicate that moving from RAP to ERAP produces a meaningful increase in savings with only a modest change in portfolio cost. Furthermore, ERAP represents a resource option with lower risk and greater environmental benefits. The enhanced RAP savings for the C&I sector are shown below in **TABLE 5**.

TABLE 5. Incremental annual C&I sector EE savings[19]

[19] AES IN 2025 IRP, Volume 1, Figure 6-34.

	2027	2028	2029	2036	2045
Incremental Annual Energy (MWh)					
MAP	101,187	103,349	107,084	130,214	143,629
RAP	78,099	80,291	83,673	105,037	116,352
Enhanced RAP	89,032	91,017	94,281	115,142	126,616

Treating ERAP as optional later is not a substitute for planning it. The IRP should determine whether and to what extent higher EE is cost-effective and risk-reducing and then inform actionable near-term program plans and budgets.

Recommendation: AES IN should: (1) incorporate ERAP, at least for C&I, as a selectable option in the primary candidate portfolio set evaluated under the scorecard; and (2) report the ERAP selection results (including savings, costs, and bundle composition by vintage and sector), rather than relegating it to a sensitivity analysis. If AES IN elects not to advance ERAP into candidate portfolios, it should provide a specific, evidence-based explanation addressing affordability and risk metrics. AES Indiana should rectify this issue in advance of its upcoming DSM plan filing.

4.3 Demand Response (DR)

4.3.1. General Note on DR Modeling

We appreciate AES IN's collaboration with OSB members in the development of its MPS and IRP inputs for demand response resources, including time-varying pricing like time-of-use rates (TOU). There are several key improvements adopted in the current studies, including further consideration of a comprehensive suite of DR products, use of average marginal line loss values, and a more nuanced bundling approach for modeling DR in its IRP. We also appreciate that AES IN has identified several new DR measures (including TOU rates) to launch within its near term 2027-2029 planning cycle based on its preferred portfolio, in addition to several other products (peak time rebates (PTR) and Battery DR, selected in scenarios without large loads) which it will consider for development as well. We urge AES IN to do so.

4.3.2. Co-Deployment and Co-Enrollment

Based on our review and understanding, AES's MPS employed a limited consideration of how effective co-deployment[20] and co-enrollment[21] strategies can influence efficiencies in increasing adoption rates and lead to increased DR savings at a lower cost. This reflects a more conservative estimate of DR resource potential (with several examples discussed below).

While we have discussed the topics of co-deployment and co-enrollment of DR and EE programs with AES IN through the OSB and in DSM cases, it is past time to develop an explicit strategy for leveraging EE and DR programs to realize increased adoption rates, savings potential, cost-effectiveness, and general engagement and satisfaction with customer participation in its DR programs. Interactions can occur through the deployment of multiple demand-side products (including EE, DR, time-varying rates, and other distributed energy resources) that can impact (1) per-unit energy savings, and (2) the likelihood of adoption and increased saturation of a given product or technology.[22]

Unlike EE where customers likely have a single point of contact (e.g., equipment rebate at time of replacement), customers will participate in DR programs over longer periods, including multiple events per season, and ideally over years of continued participation. Given the customer experience and longer duration of participation in DR programs, it is important to consider the customer journey and that customers may participate in different DR programs over time, as well as multiple complementary DR programs at the same time. It will be important for AES to develop a strategy for how to leverage

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[20] Co-deployment refers to the ability to leverage existing products, programs, or systems that encourage a combined deployment of resources, yielding benefits of interacting and achieving more cost-effective delivery. For example, combining messaging and incentives for customers to (1) purchase/install a smart thermostat and (2) enroll in a smart thermostat DR program reduces separate marketing/recruitment efforts, increases likelihood of DR enrollment (lowering incremental marketing costs), and increases both customer and power system benefits (combining conservation effects and peak load impacts).

[21] Co-enrollment refers to the ability for a customer to participate in multiple energy programs at the same time. Co-enrollment is important, particularly for demand flexibility programs, through the ability to maximize savings through customers enrolling multiple devices and participating in multiple offerings, made more cost-effective through the interaction driving increased adoption rates.

[22] Accounting for Interactivity in Resource Planning & Impacts on Demand Flexibility, Cadeo, available at https://nwcouncil.box.com/v/FlexibilityMemo; A Conceptual Framework to Describe Energy Efficiency and Demand Response Interactions, available at https://emp.lbl.gov/publications/conceptual-framework-describe-energy

existing programs, how the customer journey may take shape over near vs. longer term engagement, and how to structure eligibility requirements to encourage participation in multiple offerings (i.e., co-enrollment) to optimize the flexible load resource. AES will need to determine how to develop DR offerings that encourage engagement, satisfaction, and retention to ensure a sustainable and scalable resource over time.

Recommendation: AES IN must develop a robust strategy for co-deployment of its energy programs, including EE, DR, TVRs, and DERs. AES IN should develop a strategy specific to each EE program offering to (1) demonstrate how marketing and delivery can achieve goals of increased enablement devices and technologies, (2) embed offerings for DR/TVR/DER enrollment at optimal touch points, and (3) achieve more successful development of load flexibility programs through higher adoption rates and improved cost effectiveness.

Additionally, we recommend that AES IN develop eligibility guidelines for its complementary flexible load programs to encourage co-enrollment, thereby providing the most cost-effective opportunities to scale its DR resources. Specifically, this will include allowing participation in complementary programs, such as dynamic rates like TOU with control-based DR like smart thermostat DLC or PTR, which are not currently consistent with AES IN's characterization of these within the MPS and IRP.[23] AES IN should work with its OSB to identify a comprehensive list of complementary programs and ensure that any barriers to co-enrollment are considered and potentially addressed.

4.3.3. TOU Design and Savings

While we commend AES IN for including TOU rates within its current studies, we have observations and recommendations for moving forward. Estimates of TOU savings potential are overly conservative based on several assumptions.

First, AES IN indicated that its estimation of the eligible population for TOU adoption excludes participation in its direct load control (DLC) and curtailment DR programs.[24] Yet, these programs are complementary and should not be in conflict. As a result, the omission of these customer segments excluded a customer population with a higher likelihood of participation in TOU, which would have reflected additional savings potential at higher adoption. Furthermore, combining TVRs like TOU with DLC or

[23] AES Indiana 2025 IRP Vo1ume 1, p. 114. AES notes that it removed participants in direct load control and curtailment programs from the eligible participant population for TOU rates in estimating MPS potential.
[24] AES Indiana 2025 IRP Volume 1, p. 114.

switch-based control programs has been found to nearly double peak demand savings compared to price signals alone.[25]

Second, AES IN assumed conservative savings percentages (i.e., 8.6% and 2% of summer peak savings for residential and non-residential, respectively). These do not appear to consider rate interactions with enabling technology, like smart thermostats, which can lead to nearly double the savings (10-20%), depending on other factors like on-peak to off-peak price ratio. For example, a 2021 Brattle study identified that average residential customer peak savings are nearly double (11% vs. 6.5% for every 10% increase in price ratio) when paired with technology.[26]

Third, TVRs like TOU have a number of embedded assumptions that are challenging to fully reflect in a hypothetical snapshot of programmatic potential within MPS. For example, well designed time-varying rates are highly contingent upon peak period definitions, peak duration, and factors like the ratio of on-peak to off-peak pricing. An MPS would need to either rely on average assumptions across a range of TVRs of potentially different designs or make explicit decisions about a prototypical rate design for modeling purposes, in some cases prior to the rigor required for development of a utility-specific rate.

Extensive research has shown that dynamic rates with lower on-to-off-peak price ratios (<2-3) result in lower savings than slightly higher ratios (from 3-5).[27] As shown below, a comparison of time-varying rates by price ratio and enabling technology show that the potential for peak reduction ranges between approximately 10-20% for rates paired with enabling technology and with price ratios between 2.5 and 5. By structuring a TOU rate with a price ratio within this 2.5 to 5 range, we could expect an average savings of about 10% without technology and about 15% with technology, reflecting a significant increase in TOU savings compared to AES IN's planning assumptions.

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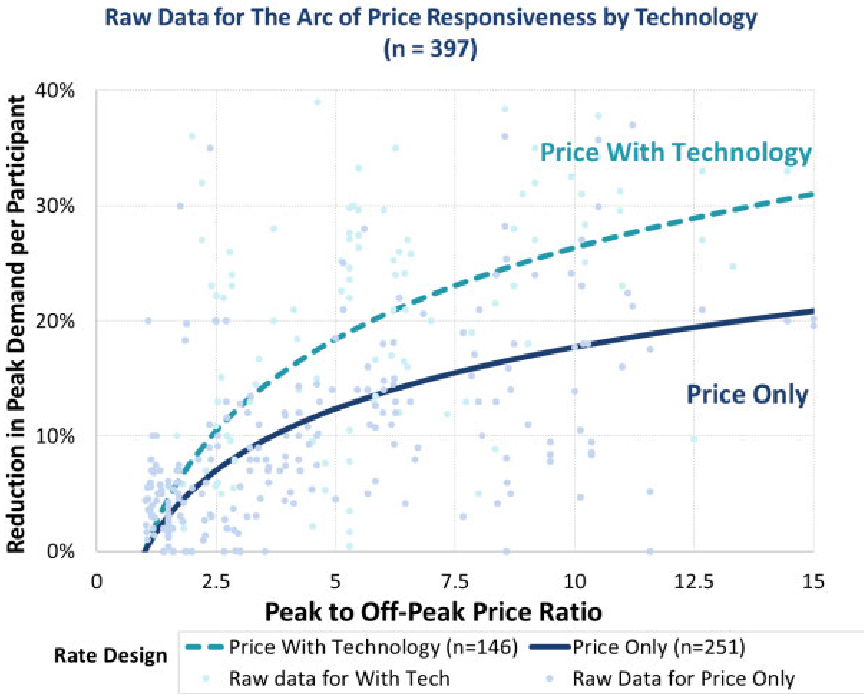
[25] Do Customers Respond to Time-Varying Rates, Brattle, available at https://www.brattle.com/wp-content/uploads/2023/02/Do-Customers-Respond-to-Time-Varying-Rates-A-Preview-of-Arcturus-3.0.pdf
[26] Moving Ahead with Time-Varying Rates (TVR), available at https://www.brattle.com/wp-content/uploads/2021/05/18500_moving_ahead_with_time-varying_rates_tvr_-_us_and_global_perspectives.pdf
[27] Do Customers Respond to Time-Varying Rates, Brattle, available at https://www.brattle.com/wp-content/uploads/2023/02/Do-Customers-Respond-to-Time-Varying-Rates-A-Preview-of-Arcturus-3.0.pdf

FIGURE 6. Comparison of TVRs by Price Ratio and Enablement Technology (Brattle 2023)[28]



Notes: Treatments that have no impact and are non-significant are excluded from the graph. RTP treatments are also excluded.

Recommendation: AES should work with its OSB to determine the optimal rate design characteristics and strategies for deployment, which should leverage other EE/DR participation in addition to customer-facing tools and efficient targeting strategies.

4.3.4. Line Loss and Underestimated DR Savings

Line loss values, which are typically expressed as an average annual percentage, represent energy lost as electricity travels through the transmission and distribution system. Actual losses vary significantly depending on the system load at any given time.

System-wide average losses differ from marginal line losses, which occur when additional load is added to the grid. Peak losses, which occur during periods of peak loads, represent the highest losses. DSM programs deliver savings directly at the margin, with DR typically occurring at peak times. When average line loss values are

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[28] *Id.*

used to reflect DSM savings at the generator, DSM benefits are undervalued. This can affect measure selection within the IRP and will inflate the levelized costs of capacity within IRPs by failing to recognize the additional value of these resource savings at both margin and peak.

The National Standard Practice Manual discusses the concepts of DSM savings occurring at the margin and the exponential growth of line loss values occurring at the margin.[29] Additionally, the Regulatory Assistance Project (RAP) released a 2011 report summarizing the dynamics of line losses at average versus marginal periods:[30] Key concepts from these resources are:

- First, marginal line losses are avoided when energy efficiency measures are installed or DR programs are dispatched.
- Second, as losses increase exponentially relative to linear load growth, losses occurring at system peak will be substantially higher than losses occurring at a system average (across all hours) or an average of marginal periods of system load. The RAP study found that marginal losses are approximately 1.5 times greater than average losses, with marginal peak losses nearly 3 times greater than average losses (e.g., 7% average vs. 20% peak).

Recent line loss studies and analyses for Commonwealth Edison (ComEd) and DTE Energy have confirmed similar relationships, with average marginal losses for energy efficiency exceeding 1.5 times the average.[31]

During the MPS stakeholder engagement process, we raised concerns with AES IN about the application of line loss values for converting demand-side resource savings (of EE and DR) from the meter to the generator. Specifically, the AES IN line loss value from the 2023 Line Loss study was based on a system average, rather than a peak marginal value, effectively underestimating the capacity benefits at the generator.

In response to our line loss discussion, AES IN proposed adopting a revised line loss value for capacity savings to more closely align with the average marginal loss value, though did not fully adopt our suggested approach to use peak marginal losses for DR.

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[29] National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources, NESP, available at https://www.nationalenergyscreeningproject.org/wp-content/uploads/2020/08/NSPM-DERs_08-24-2020.pdf

[30] Valuing the Contribution of Energy Efficiency to Avoid Marginal Line Losses and Reserve Requirements, RAP, available at https://www.raponline.org/wp-content/uploads/2023/09/rap-lazar-eeandlinelosses-2011-08-17.pdf

[31] DTE 2019 IRP; ComEd 2018-2021 Energy Efficiency and Demand Response Plan, Case No. 17-0312, Appendix A, pages 10-11, available online at https://www.icc.illinois.gov/docket/P2017-0312/documents/254601

AES IN's proposed line loss value for capacity was calculated by taking the system average value of 6.1% times the 1.5 factor from the 2011 RAP study, resulting in 9.02%.

Additionally, AES IN acknowledged a willingness to explore this issue in a subsequent line loss study, stating:

> The company would like to emphasize that we are interested in expanding our understanding of line losses as it relates to the benefits of EE and DR based on data derived from our territory. In the next line loss study, we would like to include the concepts outlined in the RAP study.[32]

While we appreciate AES IN's willingness to future explore this issue in future research and their willingness to adapt its system average line loss to more closely reflect marginal benefits for the current study, the line loss assumption, specifically for DR resources, still results in a conservative estimation of capacity savings since this reflects an average marginal loss, rather than a peak marginal loss, which could be nearly 3 times higher than a system average. Applying an average marginal line loss factor of 9%, as was done in this IRP, results in significantly lower DR savings at the generator than applying a peak marginal factor, which could be as high as 18% based on the current 6% system average.

Recommendation: AES IN should conduct a new line loss study (or adapt their existing study) to estimate both average marginal and peak marginal line loss values for applications for energy efficiency and demand response resources, respectively, before the next planning study or litigated DSM plan case.

CONCLUSION

We appreciate the opportunity to provide feedback on AES Indiana's 2025 IRP. Please refer to our compiled recommendations beginning on page three of this document.

[32] Email from AES IN DSM Research Analyst Quintin Thompson, sent 7/24/25.