March 31, 2023

Dr. Bradley Borum
Indiana Utility Regulatory Commission
101 West Washington Street, Suite 1500 East
Indianapolis, Indiana 46204 -3419
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Re: AES Indiana's 2022 Integrated Resource Plan

Dear Dr. Borum,

Citizens Action Coalition, Earthjustice, Solar United Neighbors, and Vote Solar provide the following additional comments to supplement the attached report authored for them by Energy Futures Group.

While we appreciate the constructive IRP process led by AES Indiana, we were disappointed in several aspects of the IRP, detailed further in the following sections, that led to AES Indiana selecting a preferred portfolio that includes converting Petersburg Units 3 and 4 to natural gas.

Planning

We, along with other Indiana advocates, have long pressed AES Indiana to retire its Petersburg coal-fired generation, which is a leading source of air and water pollution and carbon emissions in the state. AES Indiana has had many years to consider the retirement of this power plant and develop an orderly process and plan to replace its capacity to ensure its customers' electricity needs are met upon its retirement.

We were therefore extremely disappointed that AES Indiana waited to seriously plan for the near-term retirement of Units 3 and 4 until this IRP cycle, by which time AES Indiana claimed it was "too late" to find clean energy replacement resources if the Units were to be retired quickly. For comparison, AES Indiana's 2019 IRP considered five portfolio strategies for retiring or continuing to operate Units 3 and 4, but the earliest retirement date considered for completely retiring both units was 2030.[1] As a result of AES Indiana's delay and failure to appropriately consider earlier retirement dates in its prior IRP cycle, it told stakeholders throughout the 2022 IRP process that it would not be feasible to retire Units 3 and 4 by the 2025 timeframe if its capacity were to be replaced by clean energy alternatives (renewables, batteries, demand response, efficiency, etc.), instead making it clear that AES Indiana was really just considering gas conversion of these units. AES Indiana represented to stakeholders that replacing all of the remaining capacity at Petersburg with clean energy alternatives could be achieved no sooner than 2028. Because of this manufactured timeline by AES Indiana, its IRP resulted in some absurd results, such as AES Indiana's scorecard metrics showing that replacing Units 3 and

[1] See CAC and Earthjustice Comments on the 2019 IRP, p. 19, https://www.in.gov/iurc/files/CAC-EJ-Public-Report-Version-1.2-on-IPL-2019-IRP-4-22-2020FINAL.pdf

4 with a portfolio of renewable energy would *increase* air pollution relative to converting the Units to run on natural gas.

Portfolio Strategies

AES Indiana shared preliminary predefined Portfolio Strategies at its second stakeholder meeting.[2] Those strategies were:

- No Changes to Existing Portfolio (i.e., continue coal at Petersburg 3 and 4);
- Petersburg Refuel [to Natural Gas];
- One Petersburg Unit Retires Early (2026); and
- Both Petersburg Units Retire Early (2026 & 2028).

In other words, one portfolio would explicitly keep coal, one would explicitly convert to gas, and two portfolios would let the modeling select replacement resources to replace one or both units, respectively.

While CAC appreciates that AES Indiana was willing to modify this preliminary list of Portfolio Strategies to explicitly include an additional strategy of replacing Petersburg Units 3 and 4 with clean energy solutions, CAC was frustrated that this was a strategy that stakeholders had to proactively put forward as it should have been included in AES Indiana's initial set of portfolio strategies. This created a perception that AES Indiana's leadership had already decided from the outset that it would not be pursuing a clean energy strategy.

The implausibly low capital costs for converting Units 3 and 4 to gas (~$100/kW)[3] initially cited in IRP meeting #2 further bolstered our impression that AES Indiana seemed predisposed from the beginning of their IRP process to move towards more natural gas. While AES Indiana did ultimately revise that cost estimate upwards, CAC continues to believe that converting Units 3 and 4 to gas will not be as cheap as the estimates provided by AES Indiana in this IRP. At a minimum, we ask AES Indiana to work with stakeholders to update cost estimates in advance of any filing to convert Units 3 and 4 to gas.

Fuel Diversity

To date, AES Indiana has very little renewable energy online and already significantly relies on natural gas to meet its customers' electricity needs. In 2022, 53.8% of retail load was supplied from AES Indiana-owned coal-fired steam generation, and 34.4% came from natural gas.[4] While CAC is glad that AES Indiana is transitioning away from coal-fired generation, further

[2] April 12, 2022 IRP Stakeholder Presentation, Slide 94, https://www.aesindiana.com/sites/default/files/2022-04/AES-Indiana_IRP_Public-Advisory-Meeting-2_Presentation_Final2.pdf

[3] *Id.*, Slide 88.

[4] AES 10-K dated December 31, 2022, p. 21, https://www.sec.gov/ix?doc=/Archives/edgar/data/728391/000072839123000015/ipl-20221231.htm

increasing its reliance on volatile natural gas is risky and creates an unbalanced portfolio that is ill-suited for meeting its customers' needs into the future.

Consumers are increasingly demanding clean energy from their utilities, and there is substantial risk of new regulations being promulgated in the future that could limit or penalize carbon emissions from power plants.[5] It is at odds with consumer preferences, market trends, and regulatory risk for AES Indiana to make substantial additional investments in fossil fuel generation, particularly given it already has substantial natural gas capacity.

Reliability

Despite repeated assurances from AES Indiana, its existing natural gas generation units have not been demonstrated to be reliable sources of generation, calling into question the wisdom of AES Indiana's decision to select new investments in this resource through its preferred portfolio. AES Indiana's Eagle Valley natural gas combined cycle power plant experienced a prolonged and costly forced outage from April 2021 through March 2022. Despite company assurances of its reliability after its multiple repairs, Eagle Valley again experienced a forced outage on the precise days in 2022 when grid supplies were tightest. When Winter Storm Elliott hit Indiana on the morning of December 23, 2022, Eagle Valley, as well as a Harding Street gas steam unit, tripped offline.[6] This left AES Indiana's customers on the hook for extraordinarily high wholesale market prices that occurred during Winter Storm Elliott. It also called into question the reliability of a resource portfolio that would be even more dependent on natural gas, given AES Indiana's modern, state-of-the-art Eagle Valley facility has repeatedly shown it cannot be counted on.

Inconsistency with Corporate Commitments

AES Indiana's preferred portfolio is inconsistent with its own parent company's commitments to achieve net-zero carbon emissions from electricity sales by 2040.[7] If AES is serious about its commitment, then it implies that its future investments in converting Petersburg Units 3-4 to gas could become stranded assets by 2040.

Conclusion

We appreciate the constructive IRP process led by AES Indiana, but we remain strongly opposed to AES Indiana's decision to select a preferred portfolio that includes converting Petersburg Units 3 and 4 from coal to natural gas instead of replacing this capacity with a portfolio of affordable and less risky clean energy solutions like wind, solar, battery storage, energy efficiency, and demand response. We ask that AES Indiana continue to work with us to rectify this.

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[5] See, e.g., U.S. EPA, Pre-Proposal Public Docket: Greenhouse Gas Regulations for Fossil Fuel-fired Power Plants, September 8, 2022, https://www.epa.gov/stationary-sources-air-pollution/pre-proposal-public-docket-greenhouse-gas-regulations-fossil-fuel.

[6] Cause No. 38703 FAC 139.

[7] https://www.aes.com/aes-vision-net-zero-carbon-future-and-how-were-getting-there

Respectfully submitted,

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Report on AES Indiana's 2022 Integrated Resource Plan

Submitted to the IURC on March 31, 2023

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On behalf of CAC, Earthjustice, Solar United Neighbors, and Vote Solar

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Overview

The following comments on the 2022 Integrated Resource Plan ("IRP") submitted by AES Indiana ("Company") were prepared by Chelsea Hotaling, Dan Mellinger, Earnest White, and Anna Sommer of Energy Futures Group ("EFG"). These comments were prepared for Citizens Action Coalition of Indiana ("CAC"), Earthjustice, Solar United Neighbors, and Vote Solar ("Joint Commenters") pursuant to the Indiana Utility Regulatory Commission's ("IURC" or "Commission") Integrated Resource Planning Rule, 170 Ind. Admin. Code 4-7.

We appreciated the collaborative environment that AES Indiana created, and we look forward to continuing to work with AES Indiana in this manner. We have identified a handful issues to improve AES Indiana's next IRP.

Our review of AES Indiana's 2022 IRP and our participation in its pre-IRP stakeholder workshops raised the following main categories of concern:

- Energy efficiency ("EE") was not modeled beyond the minimum levels identified in the Market Potential Study ("MPS").
- Demand response ("DR") excluded some cost-effective measures and was not modeled beyond the minimum levels identified in the MPS.
- AES Indiana delayed in studying the retirement and conversion of Petersburg Units 3 and 4 until it was nearly impossible to take any action other than conversion to gas.
- There was little difference between the base and high load forecasts. While EV load seemed to be driving load growth, it was not disaggregated so that it could be evaluated separately from other load types.

Recognizing that a Certificate of Convenience and Public Necessity ("CPCN") is likely forthcoming, we also make the following recommendations to AES for that proceeding:

- Update input assumptions to reflect current commodity and resource costs;
- Model the full level of energy efficiency identified in AES's MPS;
- Model the full level of demand response measures in AES's MPS;
- Incorporate MISO's published information on seasonal accreditation for thermal units;
- Examine conversion of just one unit instead of two; and
- Seek detailed cost estimates for conversion of the Petersburg Units 3 and 4 to gas. Typically, such estimates would be developed through the process of securing an agreement with an engineering, procurement, and construction ("EPC") contractor and conducting a design study. Stakeholders should be intimately involved in this from the beginning.

We would also like to offer the following recommendations to AES Indiana for its next IRP:

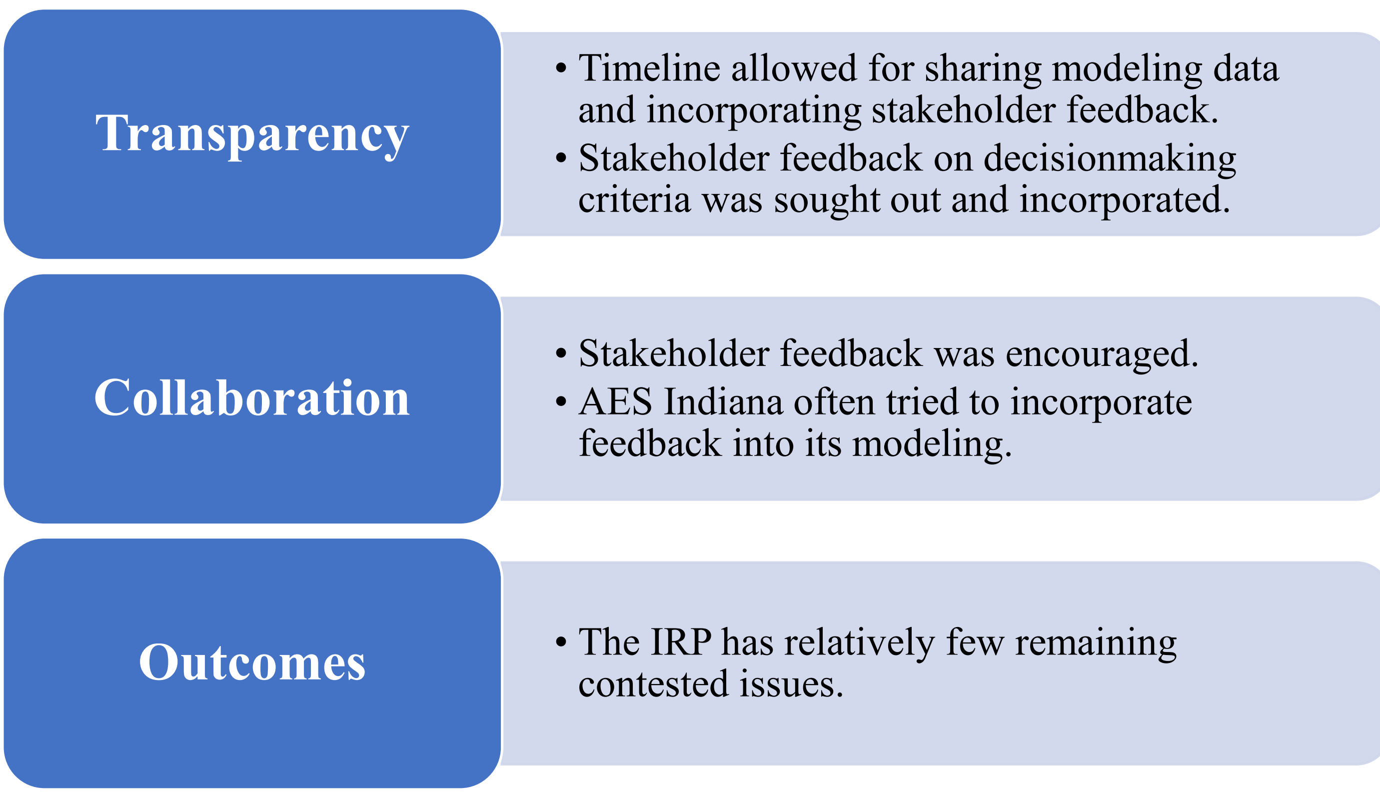
- Work with stakeholder groups to develop a scenario that evaluates industrial decarbonization;
- Incorporate all aspects of the MISO seasonal adequacy construct;

- Evaluate the economics and emission impacts of considering surplus renewable energy projects;
- Ensure that the Harding Street replacement is open to all resource technology types; and
- Hold a dedicated stakeholder meeting to discuss incorporating additional benefits of resources.

1 Stakeholder Workshops and Material Provided to Stakeholders

We wanted to first extend our appreciation for and acknowledge the quality of the IRP process that AES conducted. We appreciate the open and collaborative dialogue that AES Indiana had with stakeholders throughout the process and acknowledge the effort that AES Indiana put into trying to address issues raised by stakeholders. Figure 1 below highlights the three pillars of IRP planning that we believe are crucial for ensuring that a utility has a robust stakeholder process. These include transparency, collaboration, and implementation. We believe that the process AES Indiana conducted for this IRP is a best in class approach for how utilities can conduct their stakeholder processes, and we encourage other Indiana utilities to review AES Indiana's approach and consider making changes to their IRP processes accordingly. The following sections will talk about each pillar in turn and the aspects of AES Indiana's IRP process that provide examples of how each pillar was implemented.

Figure 1. Key Aspects of AES Indiana's IRP Process



1.1 Transparency

We view transparency as foundational to an IRP stakeholder process. Without transparency on modeling inputs, outputs, and supporting data as well as understanding the Company's decision-making process, the opportunities for learning are limited and the feedback that stakeholders can offer is, in turn, limited.

For this IRP, three important steps towards transparency are particularly worth highlighting:

1. AES Indiana created a timeline for sharing modeling inputs, outputs, and supporting data with stakeholders.
2. AES Indiana generally included sufficient time in that schedule for stakeholders to review those data, provide feedback, and for AES Indiana to incorporate that feedback into its modeling.
3. AES Indiana sought input on and was clear about the criteria it would use to judge resource portfolios.

Stakeholders willing to sign a nondisclosure agreement ("NDA") with AES Indiana were able to receive access to the modeling inputs, outputs, and supporting data. At the outset of the IRP process, AES Indiana set a schedule for what data would be released and an approximate date for the release of that information. The data shared with stakeholders included: load forecast inputs, Demand Side Management ("DSM") inputs, commodity curves, capacity accreditation for resources, new resource costs, capital expenditure and fixed O&M inputs for the Petersburg units, the EnCompass modeling input and output files, and the stochastic modeling files.

Since AES Indiana has introduced this approach for sharing information, we have found it to be an invaluable process. Rather than waiting until shortly before the IRP, or in some instances after the IRP is filed, to receive detailed information, this process allowed stakeholders to be active and thorough participants in the process. Importantly, the schedule not only allowed access to data before it was finalized but AES also typically provided enough time such that AES Indiana could consider and incorporate that feedback into the IRP – which it often did. This is in contrast to other Indiana utility stakeholder processes that do not permit information sharing until data are finalized and do not ask for feedback until the modeling is largely completed. Such a process greatly limits the scope of feedback that stakeholders can offer and largely precludes any changes in the utility's modeling to incorporate stakeholder feedback.

In our comments on AES Indiana's 2019 IRP, we expressed concern about its use of the PowerSimm model for capacity expansion and production cost modeling due to the limited ability of the model to easily export information to be shared with stakeholders. We also felt like this aspect of the model limited AES Indiana's ability to meet the technical appendix requirements in the IRP rules.[1] AES Indiana's movement to the EnCompass model for this IRP alleviated this concern because EnCompass modeling files are easily provisioned and shared through Microsoft Excel. We believe that the process AES Indiana used for this IRP satisfies 170 IAC 4-7-2(c) which requires each utility to provide input and output files in electronic format, as well as include "documentation sufficient to allow an interested party to evaluate the data and assumptions in the IRP".

Finally, AES Indiana sought stakeholder input on the criteria that it used to judge portfolios before its scorecard was finalized, and it generally incorporated that feedback, i.e., modifying the Social and Economic Impact metric per CAC's recommendation.

1.2 Collaboration

AES Indiana's emphasis on transparency also led to meaningful collaboration with stakeholders. Throughout the IRP process, AES Indiana set a tone that encouraged stakeholder feedback and generally made stakeholders feel as though their opinions were taken seriously. We feel that this hard-to-quantify element really does lead to a better IRP. It helps fulfill the purpose of the IRP process, which is to reduce areas of disagreement between stakeholders and the utility, but it also increases trust between the parties.

In many cases, AES Indiana did incorporate the feedback provided by CAC and EFG into the IRP rather than reacting defensively to criticisms and suggestions from stakeholders.

Some examples of the feedback that CAC and other stakeholders provided include:

- Adding a clean energy only replacement strategy for the Petersburg units;
- Including an industrial decarbonization strategy;
- Modeling a higher value for the social cost of carbon, especially for the Aggressive Environmental scenario;
- Modifying the natural gas and coal forecasts to reflect higher costs and volatility in prices;
- Incorporating language into the Request for Proposals ("RFP") to allow for projects that could utilize injection rights at the Petersburg site;

[1] Especially with regard to 170 IAC 4-7-2 (c): "A technical appendix containing supporting documentation sufficient to allow an interested party to evaluate the data and assumptions in the IRP. The technical appendix shall include at least the following:

(A) The utility's energy and demand forecasts and input data used to develop the forecasts;

(B) The characteristics and costs per unit of resources examined in the IRP;

(C) Input and output files from capacity planning models (in electronic format);

(D) For each portfolio, the electronic files for the calculation of the revenue requirement if not provided as an output file"

- Modeling the full level of energy efficiency identified in the MPS;
- Including a portfolio that allowed for the full optimization of new resources within EnCompass without any constraints applied to new resource builds; and
- Adding a scorecard metric to incorporate the pace of transition to clean energy, such as a percentage of annual generation from renewable resources at the midpoint and end of the planning period.

AES Indiana was willing to incorporate most of the requests outlined above, with the exception of a few items. We appreciate AES Indiana's willingness to discuss the industrial decarbonization strategy, and we hope to work with AES Indiana in future iterations of the IRP to further evolve this strategy. We recognize that the ask came further along in the IRP process and are appreciative that AES Indiana was willing to include a high electrification forecast in the Decarbonized Economy scenario to try to reflect this. We also think that the inclusion of the clean energy only and the full optimization strategy provided a more robust view of the portfolios modeled in this IRP.

The two items that were unresolved between CAC and AES Indiana included modeling a higher carbon price and making modifications to the fuel price forecasts. We recognize that not all stakeholder feedback will be incorporated for the IRP and that there will be items where there are differing opinions between the utility and the stakeholders. In these instances, it is important for both sides to feel like their concerns have been shared with the other side. From our perspective, while we disagreed with AES Indiana's standpoint on these items, we at least were able to express our concerns and then hear AES Indiana's response back to our feedback.

Following feedback provided by stakeholders, AES Indiana offered additional meetings to discuss its responses to any concerns and issues identified by stakeholders. We found this to be helpful to have an open dialogue and to ensure that all parties were able to express their viewpoints on a particular issue of concern. As we have stated, it is expected that there may be some items where there is still disagreement between the stakeholder and the utility, but having meetings where all parties involved can express their opinion helps to ensure a collaborative environment.

1.3 Outcomes

The transparency and collaboration discussed previously led to an overall high quality IRP in our view. As a result, our recommendations are relatively narrow in focus. Put another way, the outcome of this process, the IRP, while clearly an AES Indiana work product, has been shaped by stakeholders in important and meaningful ways. This is exactly the objective of a good stakeholder process, and AES Indiana is to be commended for working hard to achieve it.

2 Energy and Demand Forecast

The Company's energy and demand forecasts are developed by Itron, an established firm in the power forecasting industry. The methodology used disaggregated econometric models, forecasting each of the major classes separately, which are then adjusted using regional end-use data.[2] AES Indiana's weather-normalized annual total energy requirements and peak demand have been declining in recent years. The Company asserts that this is because energy efficiency gains have caused average customer energy use to decline at a faster rate than new customers have grown.[3] For example, the Company's energy requirements showed a compound annual growth rate (CAGR) of -1.0% from 2011 through 2021.[4]

Excluding EE, annual energy requirements average 0.5% and system peak demand 0.7% annual growth.[5] Table 1 displays the Company's annual base, low, and high energy and demand forecasts.

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[2] AES IRP at 34.

[3] *Id.*

[4] Similarly, normalized peak demand has fallen from roughly 2,900 MW in 2011 to 2,700 MW in 2021. *See* Attachment 5-2, page 5.

[5] For the purpose of resource planning, future EE program savings are excluded from the demand forecast and treated as a potential resource. The Company asserts that when the expected efficiency savings are included, the system's total energy requirements continue the declining trend through the forecast period. *Id.*

Year	Base	Low	High
2023	2,851.6	2,787.2	2,865.4
2024	2,872.8	2,807.5	2,887.2
2025	2,878.1	2,812.3	2,894.8
2026	2,885.4	2,819.0	2,904.0
2027	2,905.1	2,838.0	2,924.0
2028	2,930.2	2,862.4	2,949.4
2029	2,949.8	2,881.3	2,969.3
2030	2,968.9	2,899.3	2,988.7
2031	2,988.2	2,917.7	3,008.3
2032	3,009.1	2,937.8	3,029.4
2033	3,030.9	2,958.4	3,051.5
2034	3,054.9	2,981.7	3,075.9
2035	3,079.6	3,005.2	3,101.2
2036	3,105.1	3,029.8	3,127.4
2037	3,131.9	3,055.5	3,154.6
2038	3,158.4	3,081.0	3,181.8
2039	3,185.8	3,107.2	3,209.6
2040	3,214.1	3,133.9	3,238.2
2041	3,244.3	3,162.2	3,269.0
2042	3,275.0	3,190.6	3,300.5

Table 1. Base, Low, High Peak Load Forecasts

As Figure 1 displays further, there is little difference between the Company's base and high peak demand forecasts.[6] This suggests either the Company's base forecast is too high, or the Company's high forecast provides little additional value to the IRP and Stakeholders.

[6] Energy forecasts demonstrate a similar pattern.

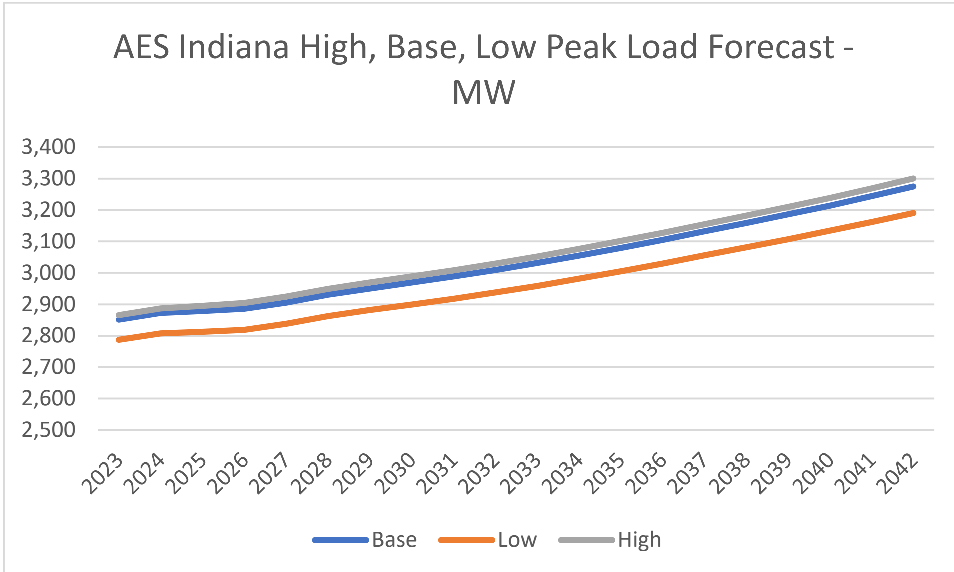

Figure 1. Base, Low, High Peak Demand Forecasts

While the Company is projecting a relatively modest growth in its load, the trend is the opposite of the Company's recent experience with declining energy and peak demand. AES states that the projected growth rates are largely caused by anticipated growth in demand caused by electric vehicles (EV).[7] The Company acknowledges the current limitations to forecasting EV adoptions and growth rates in the IRP. The Company's review of EV literature is welcome and to be encouraged.[8] We would make the following recommendations that we hope will be helpful in future IRPs to help stakeholders better understand the Company's expectations of EV growth, and the associated growth in energy demand: 1) make transparent the impacts of EV load by disaggregating it from total peak and energy forecasts; and 2) focus on making EV load as flexible as possible to ameliorate its impact on peak demand.[9]

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[7] AES IRP at 41.

[8] *Id*. at 46.

[9] Wang, H.J. et al. *Charging Load Forecasting of Electric Vehicle Based on Charging Frequency*. 2019 IOP Conf. Series: Earth and Environmental Science 237. https://iopscience.iop.org/article/10.1088/1755-1315/237/6/062008/pdf

3 Demand Side Resources

3.1 Energy Efficiency

3.1.1 Energy Efficiency Market Potential Study

AES Indiana engaged GDS Associates, Inc. ("GDS"), in August 2021 to determine the potential energy and demand savings that could be achieved by demand-side management programs. GDS and AES Indiana sought input from members of the AES Indiana DSM Oversight Board ("OSB") during the development of the market potential study through bi-weekly meetings held between August 2021 and June 2022. The opportunity for OSB input through regular and frequent meetings was valuable and appreciated.

The final MPS report was published in July 2022. EFG found the development process to be generally open and collaborative. GDS was responsive to comments and incorporated many of the recommendations provided by CAC.

The market potential study quantified the technical, economic, maximum achievable, realistic achievable, and program potential savings for the years 2024 through 2043. Each of these scenarios is described within the MPS as follows:

- **Technical Potential** is the theoretical maximum amount of energy use that could be displaced by efficiency, disregarding all non-engineering constraints such as cost-effectiveness and the willingness of end users to adopt the efficiency measures. Technical potential is only constrained by factors such as technical feasibility and applicability of measures.
- **Economic Potential** refers to the subset of the technical potential that is economically cost-effective, based on screening with the utility cost test ("UCT") as compared to conventional supply-side energy resources.
- **Achievable Potential** is the amount of energy that can realistically be saved given various market barriers. Achievable potential considers real-world barriers to encouraging end users to adopt efficiency measures; the non-measure costs of delivering programs (for administration, marketing, analysis, and EM&V); and the capability of programs and administrators to boost program activity over time. Barriers include financial, customer awareness and willingness to participate in programs, technical constraints, and other barriers the "program intervention" is modeled to overcome. The potential study evaluated two achievable potential scenarios:
    - **Maximum Achievable Potential** ("MAP") estimates achievable potential on paying incentives equal to up to 100% of measure incremental costs and aggressive adoption rates.

- **Realistic Achievable Potential** ("RAP") estimates achievable potential with AES Indiana paying incentive levels (as a percent of incremental measure costs) closely calibrated to historical levels but is not constrained by any previously determined spending levels.

3.1.2 MPS Cost-Effectiveness Screening

The MPS economic potential cost-effectiveness screening was performed as described below in the MPS:

> *In the AES-Indiana territory, the UCT considers electric energy, capacity, and transmission & distribution (T&D) savings as benefits, and utility incentives and direct install equipment expenses as the cost. Consistent with application of economic potential according to the National Action Plan for Energy Efficiency, the measure level economic screening does not consider non-incentive/measure delivery costs (e.g. admin, marketing, evaluation etc.) in determining cost-effectiveness. Apart from the low-income segment of the residential sector, all measures were required to have a UCT benefit-cost ratio greater than 1.0 to be included in economic potential and all subsequent estimates of energy efficiency potential. Low-income measures were not required to be cost-effective.*

A notable inconsistency with the IRP is that the MPS did not consider the avoided cost of carbon. The IRP Current Trends/Reference Case Scenario assumes a carbon price of $6.49 per ton starting in 2028 and escalating by 4.6% per year. Had the MPS included a similar assumption for future carbon regulation, the UCT scores for all measures would have improved, thereby enabling additional measures to be considered cost-effective. In doing so, the gap between Technical and Economic potential, shown below by sector, would have been reduced.

TABLE 4-7: RESIDENTIAL INCREMENTAL ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

	2024	2025	2026	2033	2042
MWh					
Technical	331,822	324,480	319,559	294,148	292,261
Economic	214,886	211,401	208,809	197,030	200,159

TABLE 4-14: C&I INCREMENTAL ANNUAL ENERGY EFFICIENCY POTENTIAL SUMMARY

	2024	2025	2026	2033	2042
MWh					
Technical	147,558	159,480	166,589	168,954	204,800
Economic	141,926	152,794	158,491	149,080	173,394

3.1.3 Energy Efficiency Measure Bundling

AES Indiana and GDS grouped MPS measures into "bundles" and time vintages to model energy efficiency within EnCompass. In consultation with CAC and other stakeholders, the bundles in the earliest time vintage (2024-2026) were constructed to align with the current AES portfolio of programs, while bundles in later vintages were aggregated at the sector level for ease of modeling.

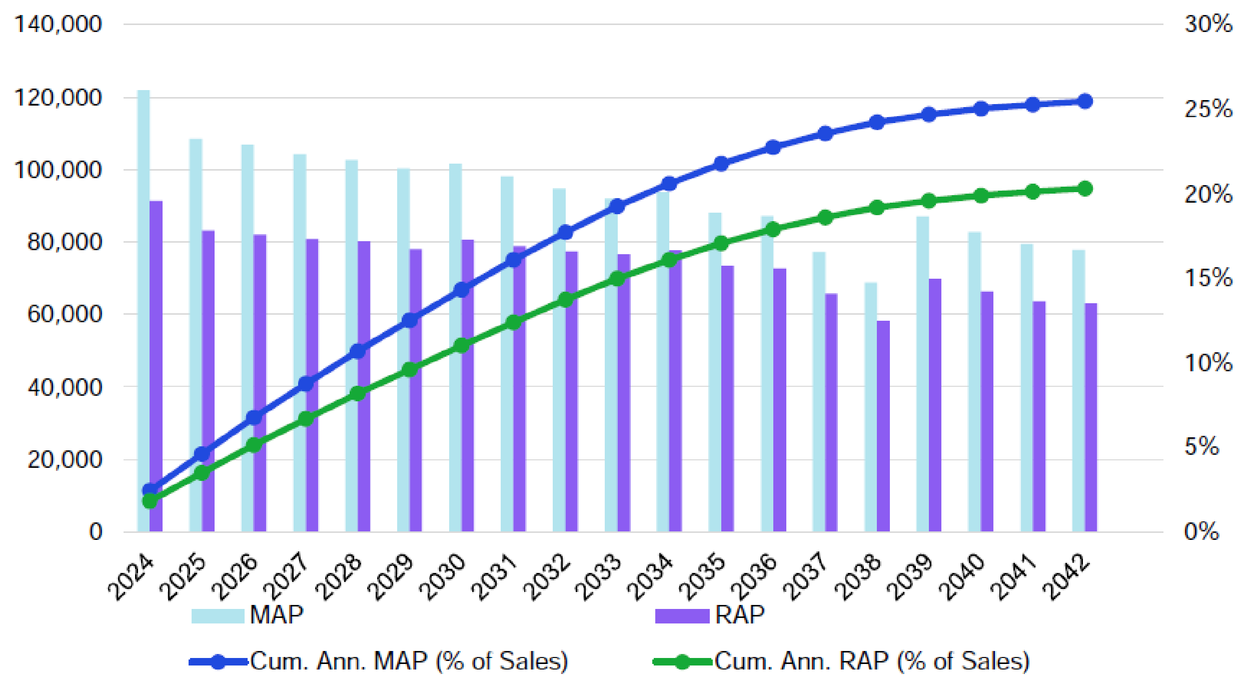
The cost and savings from the MPS RAP scenario were used as inputs when developing the bundles. The following adjustments were made to the RAP savings:

- Convert the RAP savings from gross MWh to net MWh, using the most current AES net-to-gross ("NTG") ratios from the 2021 portfolio.
- Convert the RAP savings from the meter to the generator based on known line losses.
- Include the benefit of avoided T&D based on the projected demand savings of the respective vintage-based bundles.

CAC concurs with the adjustments made. It is worth noting that AES Indiana did not apply any additional constraints or adjustments to the savings, such as artificial budget caps, adoption limits, or savings degradation.

While CAC agrees with the process to bundle and model RAP savings, we disagree with the approach to use RAP as the only source of EE savings. During stakeholder planning meetings, CAC recommended that AES Indiana also model EE savings at levels greater than RAP, up to as much as MAP, for low cost measures such as C&I. Both RAP and MAP are considered achievable, as defined above in Section 3.1.1, but MAP is based on maximized incentives while RAP is calibrated with historic incentive levels. For highly cost-effective programs and measures, particularly within C&I where the levelized costs are low based on historic incentive levels, additional savings beyond RAP could have been optimized and selected within EnCompass. The difference between C&I MAP and RAP is shown in the figure below, taken from the AES Indiana 2022 IRP Volume I. The blue line represents the cumulative savings potential under the MAP scenario.

Figure 6-69: C&I MAP and RAP Results



C&I savings in the MAP scenario are roughly 30% higher than RAP savings, as shown in the table below taken from the AES Indiana 2022 IRP Volume I. These additional energy savings opportunities were inappropriately excluded from the IRP modeling. The same concern applies to the residential sector, however given that the residential RAP bundles were already on the expensive side, it is unlikely that a significant amount of additional residential savings beyond RAP would have been optimized and selected in EnCompass.

Figure 6-70: Incremental and Cumulative Annual C&I Sector MAP and RAP Energy and Demand Savings

	2024	2025	2026	2033	2042
Incremental Annual Energy (MWh)					
MAP	121,920	108,570	106,840	92,060	77,940
RAP	91,365	83,157	82,103	76,579	63,010
Cumulative Annual Energy (MWh)					
MAP	121,920	230,491	337,295	969,667	1,313,569
RAP	91,365	174,522	256,589	754,309	1,048,015

3.1.4 Emerging Technology

The MPS analysis included a limited number of measures that might be considered emerging technologies, described by GDS in the MPS report as follows:

> *GDS considered several specific emerging technologies as part of analyzing future potential. In the residential sector, these technologies include several smart technologies, including smart appliances, smart water heater (WH) tank controls, smart window coverings, smart TVs, heat pump dryers and smart vents/sensors. In the non-residential sector, specific emerging technologies that were considered as part of the analysis include several commercial behavioral options, triple pane windows, energy recovery ventilators, variable refrigerant flow heat pumps, switch reluctance [motors], Q-Sync Motors for Refrigeration, ozone commercial laundry, advanced lighting controls, power distribution equipment upgrades, and server virtualization. While this is likely not an exhaustive list of possible emerging technologies over the next twenty years it does consider many of the known technologies that are available today but may not yet have widespread market acceptance and/or product availability.*

These measures were identified using a variety of resources including the American Council for an Energy-Efficient Economy ("ACEEE"), the U.S. Department of Energy, and the Northwest Energy Efficiency Alliance ("NEEA"). CAC commends the inclusion of emerging technologies in the MPS, however, the relatively small number of measures resulted in a very limited impact. Many of the emerging technology measures included in the study failed to pass the economic screen and therefore did not contribute to the achievable potential. Of the 291 permutations of emerging technology measures, based on home/building type, income type, and replacement type, 108 (37%) fail to pass the UCT test.

The nature of new emerging technology is such that high initial costs tend to fall as production volume and market adoption increase. The MPS analysis made no accommodation for any emerging technology to be included in the later years of the analysis if/when the measure becomes cost-effective. New technologies are regularly being introduced, and many utility programs contribute to the market readiness of these emerging technologies through pilot programs and incentives. Failure to account for these technologies results in a conservative and unrealistic view of the potential savings.

Ultimately, the RAP scenario included 24 unique emerging technology measures (12 residential, 12 non-residential). In terms of RAP savings, 10-11% of the residential sector savings, and 10-14% of the non-residential sector savings, from the first five years of the study were associated with emerging technology measures. As a point of comparison, the Consumers Energy 2021 Electric Energy Waste Reduction Potential Study, completed by Cadmus, evaluated over 200 emerging technology measures which were characterized and included in the model.[10]

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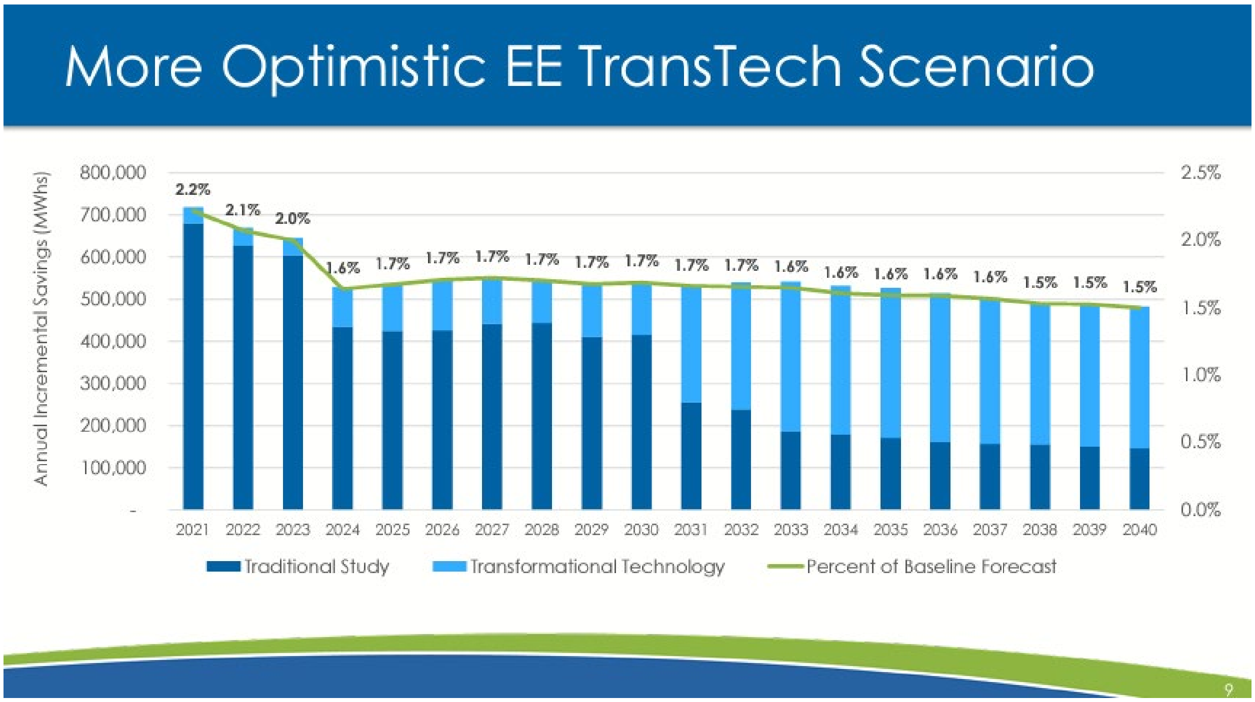
[10] Michigan PSC Case No. U-21090, Consumers Energy Co. Witness Garth, Exhibit A-81 available at https://www.michigan.gov/mpsc/-

Ultimately, 170 unique measures were included in what Consumers Energy refers to as the "Transformational Scenario." The impact of this scenario on the estimate of future achievable potential was significant, as shown in the figure below.[11] In years 3 through 9, emerging technologies account for roughly 20% of the achievable potential. In the later years of the Consumers Energy study, emerging technologies account for roughly two-thirds of the achievable potential. These results plainly demonstrate the significance of emerging technologies and highlight the importance of adequately accounting for them in a market potential study.



/media/Project/Websites/mpsc/workgroups/EWR_Collaborative/2022/Consumers-Energy-Electric-EWR-EE-Potential-Study-w-TransTech-Scenario-20210610.pdf

[11] Presentation by Consumers Energy, "Creating a Transformational Path to the Future of Energy Efficiency, Together!," available at https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/workgroups/EWR_Collaborative/2022/Transformational-EWR-Together_CE_20220719-final.pdf

3.2 Demand Response

3.2.1 Demand Response Market Potential Study

Demand response potential was evaluated as part of the GDS MPS work discussed above. The DR potential identified by GDS was grouped into maximum and realistic achievable scenarios, as was done for EE. The MAP and RAP DR potential seems reasonable and represents an increase over current levels of DR within AES Indiana territory. As a point of reference, AES Indiana states that, as of 2021, residential AC load management achieved 35 MW of demand response, and 1 MW of demand response was under contract with C&I customers.

Scenario	Sector	2024	2025	2026	2033	2042
MAP	Residential Total MW	38	47	66	247	385
	C&I Total MW (Curtailable Day Of)	9	29	94	184	203
	C&I Total MW (Curtailable Day Ahead)	9	29	122	242	263
RAP	Residential Total MW	34	39	50	166	241
	C&I Total MW (Curtailable Day Of)	2	6	30	69	76
	C&I Total MW (Curtailable Day Ahead)	2	6	45	99	107

The MAP and RAP DR potential used in the IRP, shown above, does not include any adjustments from the potential identified by the MPS.

3.2.2 Demand Response Measure Bundling

Here is the demand response bundling used by AES Indiana:

Bundle 1 – Residential DLC	Bundle 2- Residential Rates	Bundle 3 – C&I DLC / Aggregator	Bundle 4 – C&I Rates
DLC AC Switch DLC AC Thermostat DLC Electric Vehicles	Time of Use Rate Behavioral DR	DLC AC Thermostat DLC Water Heating Capacity Bidding	Time of Use Rate Interruptible Rate

Oddly, Bundle 1 does not include residential space heating and water heating direct load control (“DLC”). These two measures were found to be highly cost effective in the MPS analysis. DLC space heating had a UCT score of 5.81 and DLC water heating was 1.85. Meanwhile, the DLC electric vehicles measure was found to be not cost effective (0.65 UCT) but is still included in Bundle 1. As a result, Bundle 1 was only selected in 2 of 6 generation strategies evaluated in the IRP (Both Petersburg Units Retire, and Clean Energy). Bundle 1 could have performed better in the other strategies with the addition of DLC space heating and DLC water heating.

Similarly, Bundle 3 omits C&I DLC space heating despite being cost effective in the MPS analysis under the RAP scenario (1.46 UCT) and even more so under the MAP scenario (3.52 UCT). Bundle 3 was not selected in any of the IRP generation strategies.

As with the EE measure bundling, DR potential was only considered at the RAP level. The MAP scenario includes greater levels of cost-effective DR, especially on measures contained within Bundle 4 (C&I curtailable/interruptible rates and time of use rates). Furthermore, the cost-effectiveness for some measures, such as residential DLC AC thermostats, C&I DLC space heating, C&I DLC water heating, and C&I capacity bidding, *improves* under the MAP scenario. *AES Indiana should have modeled the DR potential from MAP scenarios, or at least an optimized RAP/MAP blend, within its IRP. Absent this modeling, the selected DR potential underrepresents what can be achieved.*

4 EnCompass Modeling

We recognize the challenges that AES Indiana faced to incorporate the most up to date modeling inputs for this IRP. These challenges included the move to MISO's seasonal resource adequacy construct, supply and inflationary pressures for new resources, rising fuel prices, and the passage of the Inflation Reduction Act ("IRA"). We recognize the effort that AES Indiana put into modeling the MISO seasonal construct with the information it had available at the time the IRP modeling inputs were being developed. However, since that time, MISO has released additional information that we recommend should be incorporated in future IRPs (and prior to any resource proceedings like a CPCN) including seasonal planning reserve margins and seasonal accredited values for AES Indiana's thermal units (not merely UCAP values). We also appreciate that AES Indiana updated new resource information to reflect the IRA tax credits.

4.1 Timeframe for Petersburg Units 3 and 4 Retirement

AES Indiana's 2019 IRP studied portfolios that included the retirement of Petersburg Units 3 and 4 in 2026 and 2030, respectively. Both those portfolios show the need for additional new capacity in the 2022 – 2026 timeframe, beyond that to facilitate the retirement of Petersburg Units 1 and 2. This IRP both accelerated the timeframe for retirement of Petersburg Units 3 and 4 and introduced a new option – conversion of those units to gas. But despite the learnings from the prior IRP about the timing and need for replacement generation just to facilitate one retirement in 2026, the length of time in which alternatives could be brought online was shortened both because the analysis waited until the 2022 IRP and because retirement was brought forward by a year for Petersburg Unit 3 and by five years for Petersburg Unit 4. This largely foreclosed any alternative to conversion of the units in 2025. This speaks to the need, not just for AES Indiana but any Indiana utility, to thoroughly and quickly explore alternatives to existing generators, so that flexibility and optionality is maintained and the utility is not locked into a specific decision due to timing.

4.2 MISO Seasonal Resource Adequacy and Thermal Accreditation

AES Indiana modeled the MISO Seasonal Resource Adequacy construct by including seasonal planning reserve margins and seasonal accreditation for renewable resources. However, one recommendation we have is that AES Indiana should have considered the changing accreditation of its thermal units across the seasons as it did for renewables. AES Indiana's Eagle Valley unit accreditation has almost certainly been impacted by its nine month outage in 2021 and 2022. As such, we made the recommendation that its accreditation, as well as that of other AES Indiana thermal units, be based on its performance consistent with MISO requirements rather than assume what amounts to a UCAP value. AES Indiana argued that the outage was an outlier and should not reflect long-term performance, but Eagle Valley appears to have been at least partially down in December 2022 including during Winter Storm Elliott, which will almost certainly negatively affect its accreditation again.

We also recognize that MISO has released additional information since the time that AES Indiana developed this for its IRP. Figure 2 below shows the MISO Schedule 53 Class Averages for the 2023/2024 Planning Year. These class averages show the seasonal accreditation (before adjustment for MISO's seasonal UCAP/ISAC ratios, which does not affect relative accreditation among technologies) across the different resource technologies within MISO. These values show that the traditional approach of looking at the nameplate of a unit less its forced outage rate does not capture the full risk that these accredited values show across the seasons.

Table 2 indicates that the seasonal risk associated with thermal units is not uniform – class average accreditation is generally lower in the winter and higher in the summer. We recommend that AES Indiana incorporate the most recent information on the seasonal construct and resource accreditation from MISO in in any resource proceedings relying on the 2022 IRP and in future IRPs.

Table 2. MISO Schedule 53 Class Averages for 2023/2024 Planning Year[12]

Row Labels	Summer ISAC/ICAP	Fall ISAC/ICAP	Winter ISAC/ICAP	Spring ISAC/ICAP	Count of Units
Combined Cycle	88.17%	76.50%	80.06%	74.07%	106
Combustion Turbine 0-20MW	83.32%	82.79%	77.35%	79.01%	40
Combustion Turbine 20-50MW	87.51%	82.45%	81.64%	81.75%	118
Combustion Turbine 50+MW	91.41%	80.85%	79.78%	84.32%	174
Diesels	90.34%	85.34%	82.95%	86.77%	66
Fluidized Bed Combustion	[redacted]				8
Fossil Steam 0-100MW	81.90%	78.39%	77.60%	75.55%	52
Fossil Steam 100-200MW	[redacted]				28
Fossil Steam 200-400MW	84.15%	72.85%	76.08%	74.34%	33
Fossil Steam 400-600MW	79.45%	75.36%	80.57%	75.10%	34
Fossil Steam 600-800MW	[redacted]				24
Fossil Steam 800+MW					4
Hydro 0-30MW					14
Hydro 30+MW					8
Nuclear					17
Pump Storage					14
FleetWide Schedule 53 ISAC/ICAP	85.93%	78.48%	79.25%	78.53%	740

4.3 Black Start Decision

One of the replacement resource decisions that AES Indiana modeled in this IRP is the replacement of Harding Street Units 1 and 2 (total installed capacity of 38 MW). These units are scheduled for age-based retirement by the end of 2024 and are part of AES Indiana's black start plan. In the model, AES allowed EnCompass to select either a reciprocating engine or a diesel unit to replace the units when they retire.[13]

[12] Retrieved from https://cdn.misoenergy.org/20221215%20Schedule%2053%20Class%20Average627347.pdf

[13] AES Indiana 2022 IRP, page 152.

It was not clear to us whether a replacement analysis for the units was performed prior to modeling these two resource replacement options for Harding Street Units 1 and 2. We ask that AES Indiana consider the ability for some or all the capacity to be replaced with battery storage resources. It is our understanding that battery storage resources with Grid-Forming Inverters ("GFI") have the capability to provide black start and that the technology is available.

4.4 Progress on Clean Energy

In the IRP, the scorecard indicates that the Petersburg Conversion generation strategy[14] will have a 55%[15] renewable energy and DSM share by 2032.[16] This was one of the metrics that CAC requested that AES Indiana include in the scorecard to measure the progress towards a clean energy transition. We appreciate AES Indiana incorporating this into the scorecard. The capacity additions from the Petersburg Conversion Strategy indicate that there is some solar hybrid capacity added in 2025 with standalone solar starting to be selected in 2030. The model also selects some wind in 2026 and 2027.

In order to increase the progress on clean energy and reduce the exposure to volatile natural gas prices, we recommend that AES Indiana consider the potential to add surplus interconnection projects at the Petersburg locations if AES Indiana moves forward with converting Units 3 and 4 to gas. In other jurisdictions, we have seen utilities take advantage of using surplus interconnection for solar and wind projects at existing thermal generation sites, such as combustion turbines. Under this framework, the renewables would not receive capacity credit until the thermal resource is retired. However, the surplus interconnection would allow for the addition of more renewable resources that could operate during periods when the thermal resource is not. We have seen proposals from other utilities that would either allow for renewables at the site of the thermal plant or, through the use of a gen tie line, that could incorporate renewable projects at other locations. We recommend that if AES Indiana moves forward with the conversion of the Petersburg units, that AES Indiana explore this possibility as a way to incorporate more renewable energy for their system. Northern States Power in Minnesota is using a similar approach to replace energy and capacity at its Sherburne power plant site.[17]

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[14] Petersburg 3 and 4 are converted to gas in 2025 under this portfolio.

[15] As shown in Figure 9-17 of page 199 of the 2022 IRP, the generation mix will be 17% wind, 31% solar, and 7% DSM for the total of 55%.

[16] AES Indiana 2022 IRP, Figure 9-17, page 199.

[17] https://mn.my.xcelenergy.com/s/about/newsroom/press-release/xcel-energy-proposes-minnesota-energy-connection-power-line-to-replace-retiring-MCH2FCUPO3HRFWTBHJGADEMXUTY4

4.5 Scorecard Metrics

One of the metrics that AES Indiana included in the scorecard is a "Market exposure risk variable" which calculated the average of the absolute value of the annual sales and purchases and then added the sales and purchases together over the 20-year period. We find adding together the sales and purchases to be confusing and would suggest that if AES Indiana wants to incorporate market risk for future IRPs, then AES Indiana should consider a metric such as market purchases as a percentage of annual energy and market sales as a percentage of annual energy.

4.6 Consideration for the Next IRP

AES Indiana flagged that the Harding Street Units ST5, ST6, and ST7 (about 620 MW ICAP) age-based retirements will be an important item for consideration in the upcoming IRPs. AES Indiana said in the IRP that it will "[m]odel alternative replacement resource options such as clean hydrogen or small modular reactors if commercially viable: AES Indiana intends to monitor new and emerging technologies for feasibility as future replacement resources. If technologies like clean hydrogen or small modular reactors are deemed viable, then they may be included as replacement resources in future IRPs."[18]

We look forward to collaborative discussions with AES Indiana about the resources to be modeled for the replacement of the Harding Street Units. We would like to see AES Indiana model longer duration battery storage resources, such as 8- and 10-hour batteries as well as options for multiday storage such as Form Energy's iron air battery.

One of the other items that AES Indiana discussed in its IRP is sub-hourly modeling to capture additional benefits of battery storage and reciprocating engines. AES Indiana stated, "This value may be more accurately captured through sub hourly modeling, though this currently pushes the limits of many available models and forecasts. AES Indiana will continue to assess whether the value of more granular modeling justifies the increase in complexity."[19]

Other utilities are also exploring more granular modeling to accomplish similar aims and could be good examples for AES Indiana to review in advance of its next IRP process. For instance, NIPSCO's IRP incorporated an analysis from Charles River Associates to incorporate additional benefits outside of the model, and DTE's recently filed IRP also considered the ancillary and flexibility benefits of battery storage resources. We recommend that AES Indiana set aside a specific meeting to discuss modeling approaches with stakeholders for the next IRP.

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[18] AES Indiana 2022 IRP, page 262.

[19] AES Indiana 2022 IRP, page 263.

5 Conclusion

In sum, we found the AES Indiana IRP process to be of high quality and one that left relatively few issues unresolved. Those that were unresolved included the modeling of energy efficiency beyond minimum levels identified in the Company's MPS, the exclusion of some cost-effective demand response measures and failures to model those beyond the minimum levels in the MPS, the failure to disaggregate the load forecasts to separately evaluate EV load, and certain modeling related concerns such as the resource adequacy requirements, units designated as black start capable, etc.

We look forward to seeing the continued collaborative nature of this IRP process replicated in other forums with AES Indiana such as the DSM Oversight Board meetings, in advance of certificate of need cases, and, of course, the next IRP cycle.