Indiana Office of Utility Consumer Counselor's Comments on Indiana Michigan Power Company's 2024 Integrated Resource Plan August 15, 2025

I. INTRODUCTION

The Indiana Office of Utility Consumer Counselor ("OUCC") offers its comments and recommendations regarding Indiana Michigan Power Company's ("I&M") Integrated Resource Plan ("IRP") submitted to the Indiana Utility Regulatory Commission ("Commission") in March 2025.

I&M held a series of IRP Stakeholder meetings from June 2024 through March 2025, and the OUCC appreciated the opportunity to participate. OUCC staff also participated in separate technical meetings.

I&M has continued to respond to questions from its IRP Stakeholder meetings and comments raised in prior IURC Research, Policy, and Planning Division Director Reports and OUCC submissions. The purpose of these comments is to recommend improvements to I&M's IRP processes and Preferred Portfolio development for the benefit of Indiana's consumers.

As with all Indiana investor-owned electric utilities, the ultimate preferred resource portfolio and action plan decisions are I&M's alone and are ultimately not determined by participating stakeholders.

It is also crucial to note that when the OUCC does not address specific items, assumptions, or portfolios in its comments, this should not be interpreted as support on those matters. It is impractical to weigh in on every single issue given the amount of information and level of depth in which subjects are covered in these plans. The impracticality of addressing all issues is exacerbated by the rapidly evolving nature of the electric industry and lack of predictability regarding future developments in both the short term and long term.

Regarding I&M's 2024 IRP, the OUCC offers the following general observations and recommendations:

- I&M should provide estimated future bill impacts for its residential customers and traditional commercial customers, as is typical for Indiana electric utilities.
- I&M should clearly and thoroughly detail the impacts of new Hyperscale Load ("HSL") customers. The impact should be distinct from the impact on current customers under all classes (Residential, Commercial, and Industrial), due to the magnitude of the projected capacity increase. I&M should exclude its 5% "capacity contingency," which is not justified by an analysis of the benefits versus the likely additional costs to ratepayers.
- I&M should model greater variability in its load forecast reflecting the uncertain demand requirements of its new HSL customers.
- I&M should recognize and adjust any projected impacts from carbon regulation in the model for the new possible timeframe for such regulations.
- To fairly evaluate potential energy sources, I&M should broaden its environmental sustainability criteria beyond carbon, NOx, and SO2 emissions.
- I&M should run statistical tests to provide validation that the preferred portfolio is sufficiently different from its other portfolios. Otherwise, it would be misleading to suggest the preferred portfolio is best.
- I&M should clarify how four of the fifteen portfolios yielded the exact same resource selection as the Base portfolio sensitivity and explain the significance of these results and basis for exclusion from the final selection.

- I&M should supplement its qualitative resilience assessment with quantitative metrics (e.g., outage duration recovery speed, customer outage impact metrics, and system hardening benefit metrics) and stress-test resilience under extreme scenarios.
- I&M should expand its stability analysis to include engineering parameters (e.g., frequency, voltage, inertia) and assess how planned resources will mitigate stability risks, including impacts from transmission congestion and regional stress events.
- I&M should include additional metrics models such as SAIDI/CMI/CI metrics and model EV/DER impacts on service outages.

II. FIVE PILLARS OF ELECTRIC UTILITY SERVICE

The OUCC reviewed how the attributes of each of the Five Pillars of Electric Utility Service are addressed in I&M's IRP consistent with the Commission's General Administrative Order 2023-04 acknowledging House Enrolled Act 1007 (2023), Ind. Code § 8-1-8.5-3.3. For IRPs submitted after June 30, 2023, the Commission's Research, Policy, and Planning Division Director must evaluate whether an IRP's preferred portfolio takes the Five Pillars into account. Indiana Code § 8-1-8.5-4(b) requires the IURC to consider, when evaluating a CPCN request, whether the construction of the proposed facility will result in electric service consistent with the attributes of the Five Pillars as defined in Ind. Code § 8-1-2-0.6.

Affordability

I&M's affordability analysis does not include customer bill impacts, instead using "Near-Term Rate Impacts," which are defined as the Compound Annual Growth Rate of *Power Supply Costs*.[1] Instead of showing the bill impacts for different customer classes, I&M shows the

[1] I&M IRP, p. 188.

average cost of electricity over time and not how these costs will be allocated to I&M's different rate classes. This is problematic because it is crucial, from a ratepayer protection standpoint, to know the impact I&M's significant new HSL load will have on current customers. As in other utilities' IRPs, I&M should include the average bill impact, especially for its typical residential and commercial customers.

Rates for all five of Indiana's investor-owned utilities have increased significantly in recent years as reflected in the IURC's annual Electric Residential Bill Surveys. Accordingly, it is increasingly important for all stakeholders to understand the financial ramifications an IRP and individual generation projects will have on short-term and long-term rates.

Resiliency

Although I&M addresses resiliency, its evaluation of this Pillar is qualitative and based largely on the resource mix, diversity, and ability to meet load under the modeled scenarios. I&M does not include more granular or quantitative resilience indices — such as outage duration recovery speed, customer outage impact metrics, or specific system hardening benefits — resulting in a measurement that is broad rather than operational. While I&M's IRP considers market exposure, resource diversity, and capacity contingency, the resilience discussion is primarily at the planning level and does not show detailed performance modeling under extreme or prolonged stress events. There is minimal evidence of resilience scoring being stress-tested against scenarios beyond typical capacity and energy reliability modeling. Beyond resource adequacy modeling, there is no clear tracking metric for how these decisions tangibly improve resilience over time. Not including these evaluations leads to underestimation of the costs associated with weather events that are (relatively) low risk and high impact and other shocks to I&M's system that are outside of the Company's control.

Reliability

The IRP offers limited discussion regarding standard reliability metrics such as System Average Interruption Duration Index ("SAIDI"), Customer Minutes of Interruptions ("CMI"), and/or Customer Interruptions ("CI"), even though these measures are commonly used to benchmark customer experience. While I&M does reference reliability through risk modeling, it does not explicitly assess how increasing electrification DER integration may affect outage durations or frequencies. The OUCC recommends I&M include a more robust analysis or at least a preliminary modeling of how varying levels of EV and DER penetration may shift reliability metrics and how different resource portfolios mitigate related reliability risks. This analysis would show how different rates of electricification influence the proportion of generation resources in the Company's ultimate preferred portfolio. This analysis could also help to identify the areas in I&M's service territory that are most susceptible to reliability risks associated with increasing customer electrification.

Stability

I&M recognizes stability in its portfolio scoring and acknowledges the roles of local resource diversity and reduced market dependence. While the IRP includes an "Energy Market Exposure" metric, it primarily addresses economic exposure, not operational stability impacts (e.g., transmission congestion effects on voltage stability or dependency risks during regional stress events). The way I&M addresses stability is mostly framed in terms of resource planning rather than grid operational characteristics. The IRP treats stability as a high-level system attribute rather than a measurable engineering parameter (e.g., frequency response, voltage regulation, etc.). There is no clear discussion of system inertia changes from resource retirements, potential short-circuit strength impacts, or how planned resources would mitigate stability concerns at the transmission level.

Environmental Sustainability

The criteria I&M used for measuring environmental sustainability are the reductions in total carbon dioxide ("CO2"), nitrogen oxide ("NOx"), and sulfur dioxide ("SO2") emissions from I&M's generating sources from a baseline of 2005 levels to projected emissions in 2034 and 2044.[2] I&M does not explain why only these emission types were selected or why it decided to focus solely on these three air emission types or only on air emissions when determining environmental sustainability.

The focus on these three air emission types will bias the results toward the transition away from coal resources, and I&M will meet these metrics from the already planned closure of the Rockport Generating Station. To properly evaluate environmental sustainability across the I&M fleet, I&M should broaden its metrics to consider other air emission types such as carbon monoxide ("CO") and volatile organic carbon, which are emission concerns for natural gas plants. I&M should also look at water and waste impacts, including wastes from decommissioning of wind and solar farms. This would allow a better comparison for environmental sustainability of all available energy source options.

[2] I&M IRP, Section 2.3.5 Environmental Sustainability, p.26.

III. ADDITIONAL ISSUES

New Capacity Contingency Proposed for the Load Forecast

I&M is proposing a new 5% "Capacity Contingency" to account for uncertainty in the peak load forecast and the amount of capacity accreditation assigned to different resource types.[3] This has previously been unnecessary for I&M's resource planning and will add hundreds of millions of dollars to its revenue requirement. According to I&M, adding this capacity contingency is prudent "to address risks associated with load requirements and capacity accreditation that are largely outside the utilities' control."[4] However, adding capacity above the reserve margin, which PJM determines, creates new financial risks for existing customers, as ratepayers will ultimately pay for new generation. I&M cites possible capacity deficiency charges for not meeting the Fixed Resource Requirement ("FRR") which PJM also determines.[5] However, I&M does not present an analysis of the additional costs that will ultimately be borne by its ratepayers to meet its new 5% capacity contingency above the FRR. I&M's analysis of the risks associated with not meeting its FRR is not compared to the costs that ratepayers would pay to mitigate this risk. Such a comparison is necessary because it would show the tradeoffs between planning to meet a higher reserve margin and keeping costs reasonable and prudent for ratepayers. In the absence of such an analysis, the proposed capacity contingency should be removed from the IRP.

3 2024 IRP, p. 84.
4 I&M IRP, p. 84.
5 *Id.*

Load Uncertainty

Despite the new HSL customers on I&M's system, the boundaries of the high and low economic growth[6] (and consequently high and low load forecast) are approximately the same or even smaller than in the 2021 IRP.[7] The long-term load forecast depends upon economic growth as a key factor; therefore, it would be useful to include variations in the demand of a few large HSL customers. For example, a lower boundary for the load associated with HSL customers could be determined based on the Settlement Agreement provision approved in IURC Cause No. 46097. This agreement states that a "Large Load Customer may, without payment of an Exit Fee or any penalty, reduce its contract capacity at any time after the first five years by up to 20%, in total, by giving I&M at least 42 months written notice prior to the beginning of the PJM Delivery Year for which the reduction is sought."[8] Such a lower boundary, after five years, would help show the impact on existing customers if HSL customers end up requiring less power than is forecasted, rather than simply holding HSL constant as is done in I&M's 2024 IRP.[9]

Current Customer Impact from Large Load

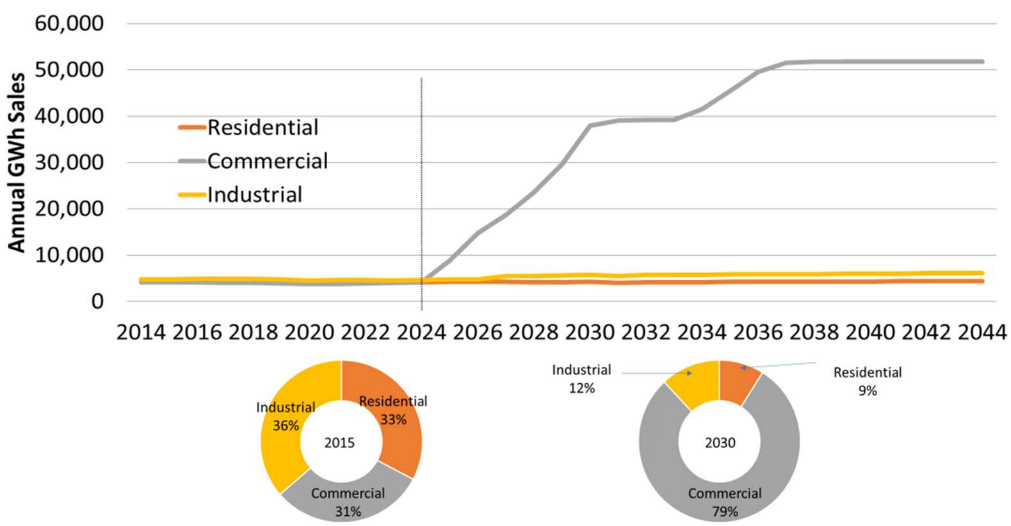
Although I&M must plan for a large increase in demand, its 2024 IRP needs to clearly delineate new large load customers from the utility's current customers. Otherwise, without clear separation, it appears the current generation portfolio's net present value of revenue requirement ("NPVRR") increases unfairly for current customers.

To explain this observation, I&M projects the power demand will double and the NPVRR will quadruple within the next 20 years. Taking the information (shown in OUCC Figure 1, below) I&M shared at its second 2024 IRP Stakeholder Meeting on September 24, 2024, and reasonably

[6] 2024 IRP, p. 53.
[7] 2021 IRP, p. 53.
[8] Cause No. 46097, Submission of Unopposed Settlement Agreement, p. 4.
[9] 2024 IRP, p. 127.

assuming no significant changes, the percentage of energy sales in 2015 relative to the impacts of new HSL customers essentially remained flat between 2015 and 2024. Commercial customer levels from 2015 can be used to estimate Commercial customer levels projected in 2030. However, in 2025, there is a noted increase in energy sales associated with new HSL customers. As seen in Figure 1 below, prior to the addition of new HSL customers, existing Commercial customers accounted for approximately 31% of energy sales in the 2015-2024 period. By 2030, I&M's existing Commercial customers would account for roughly 9% of those energy sales, i.e., the 79% portion of sales attributable to total Commercial customers, which will include HSL customers.

Figure 1: (I&M's) Indiana GWh Sales (Weather Normalized History & Forecast)[10]



Approximately 30%[11] of the $33.1 billion preferred portfolio NPVRR (or $9.9 billion) is projected to be paid by I&M's current customers. As is shown in OUCC Table 1 below, using estimates for inflation from the CPI and I&M's 2021 IRP net present value, a revenue

[10] Second I&M Stakeholder Meeting Presentation on 9/24/2024, slide 7.
[11] Using 9% of sales attributable to current Commercial customers added to 12% sales from Industrial customers and 9% sales from Residential customers.

requirement of $8.2 billion in 2025 dollars would be required to serve existing customers. This leaves $1.7 billion of increased costs for existing customers that appear to be due to the new HSL customers, relative to an inflation adjusted revenue requirement using I&M's 2021 IRP costs.

To arrive at the rationale that current customers appear to see an increase in their NPVRR, one would assume energy[12] and capacity[13] needs of current customers remain relatively unchanged so that I&M's 2024 IRP preferred portfolio would be practically identical to the preferred portfolio in I&M's 2021 IRP. Therefore, one would take I&M's 2021 IRP preferred portfolio NPVRR of $6.76 billion and inflate the cost to a current 2025 value, shown in OUCC Table 1 below:

OUCC Table 1

Year	Year-End Inflation (%)[14]	Inflated $6.76 B
2021	7.0	$6.76 B
2022	6.5	$7.23 B
2023	3.4	$7.70 B
2024	2.9	$7.97 B
2025	N/A	$8.20 B

Compared to the 2021 IRP preferred portfolio NPVRR, accounting for inflation, the 2024 preferred portfolio IRP NPVRR appears to estimate a $1.7 billion increase for current customers. This is seemingly due to the addition of new large-load customers' demand. The OUCC

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[12] Figure 1 historical energy sales, sourced from footnote 9.

[13] Capacity compared from (1) I&M 2021 IRP: Appendix 1 – Exhibit F: I&M Internal Hourly Load Data and (2) I&M 2024 IRP: Appendix 1 – Exhibit L: I&M Indiana Hourly Load.

[14] U.S. Bureau of Labor Statistics, Historical Consumer Price Index for All Urban Consumers, found at: https://www.bls.gov/cpi/tables/supplemental-files/historical-cpi-u-202412.pdf.

acknowledges assumptions and extrapolations were made; however, this underscores the necessity for I&M to provide information distinguishing: (1) new and large load customers within the Commercial Class and (2) in the absence of a full cost of service study, a basic analysis of NPVRR on how each class is impacted, i.e., information demonstrating current customers will not be adversely impacted by large load customer demand. Safeguards for existing customers were a crucial consideration in the Cause No. 46097 Settlement Agreement allowing I&M to offer a standard tariff for HSL customers. These safeguards include such terms as exit fees and minimum demand charges.[15] Protection of existing customers should also be a priority for long-term resource planning. Therefore, the OUCC recommends I&M:

1. Clearly and thoroughly address how current customers will not incur any cost increases because of I&M's new large-load customers, as compared to its 2021 IRP preferred portfolio which did not contain HSL customers; and
2. Separate the HSL customers from current customers, either with a separate Commercial category in the IRP or a completely new category.

Portfolio Sensitivities Require Further Validation

In Figures 98, 99, and 100 of the I&M 2024 IRP, the OUCC cannot distinguish by visual inspection a difference between the final four portfolios[16] after sensitivity risk analyses. One way to address this would be statistical tests. Otherwise, it is misleading to indicate one portfolio will outperform the other portfolios under different sensitivities. The OUCC recommends statistical tests be performed to confirm the portfolio sensitivities were distinguishable and therefore, legitimize choosing a preferred portfolio. Recommended statistical tests are:

[15] Settlement Testimony of Andrew J. Williamson, Tariff I.P.
[16] Base, Carbon-Free Sensitivity Low Carbon: Transition to Objective, EER: Expanded Wind Availability, and Preferred.

1. ANOVA (Analysis of Variance), which is a statistical test used to compare the means of two or more groups. If the ANOVA test result is statistically significant, it suggests that at least one sensitivity is different from the others, but not necessarily which one.
2. Tukey's HSD (Honestly Significant Difference) Test, an all-pairwise comparison between groups that complements the ANOVA test. It would show which portfolio sensitivities are statistically different from each other.
3. The Kruskal-Wallis Test compares medians of two or more groups. It is useful when the data is not normally distributed or when the sample sizes are small. Since ANOVA assumes a normal gaussian distribution, it makes sense to compare ANOVA using a statistical test that does not have the same assumptions as ANOVA.

Four of the fifteen[17] (26.7%) portfolio sensitivities obtained the same resource selection as the Base portfolio sensitivity, even with varying resource cost assumptions, which significantly changes affordability as measured by the short-term seven-year (2024-2031) Compound Annual Growth Rate ("CAGR"). I&M needs to provide further clarification and justification.[18]

Electric Vehicles

The OUCC recommends I&M provide additional justification for its assumed 12% annual EV growth assumptions, particularly given regional adoption patterns. The 2024 IRP Public Summary states EV penetration in Indiana starts from a relatively small base and grows at 12% annually; however, no regional comparison was provided that supports this growth rate. The

[17] High Technology Cost, Rockport Unit 1 Retires 2025, Rockport Unit 1 Retires 2026, Exit OVEC ICPA in 2030.
[18] Analogy: Ingredients (resources) are required to bake a cake (meeting capacity and energy needs). If only the price of eggs (one resource type) rises significantly, you might consider substituting eggs with yogurt or even a mix of water, oil, and baking powder (one or a mix of other resource types). If the cost of all the ingredients rises relatively the same, you would still buy all the same ingredients. It would just be a more expensive cake (higher short term seven-year CAGR). This is what appears to be the case for a quarter of the portfolio sensitivities.

OUCC suggests I&M model a more conservative sensitivity such as the East North Central region's approximate 9% adoption by 2035, based on the Annual Energy Outlook 2024 Reference Case, to view a slower EV deployment scenario.[19] This is important because a mismatch between forecasted EV load and actual adoption could result in stranded costs or overbuilt infrastructure. Further, while I&M has acknowledged the long-term implications of vehicle electrification on system planning, the IRP should also consider emerging technologies such as vehicle-to-grid (which remains uncertain, especially for fleets like school buses) to include managed charging and thermal energy storage. Additionally, it would be particularly worthwhile for I&M to re-evaluate its estimates for vehicle electrification rates in light of the current federal Administration's approach to EV incentives and EPA rules, which may slow EV growth and make I&M's projections less realistic.

Demand Side Management

The IRP references a net-to-gross ("NTG") methodology aligned with the IURC Cause No. 45546 Settlement Agreement but does not provide sufficient detail on how NTG ratios were applied across different customer classes or measure types. This lack of documentation impedes the OUCC's ability to assess whether the DSM savings assumptions are conservative or overstated. Detailed NTG assumptions are needed to understand the actual achievable impacts of energy efficiency ("EE") programs.

In addition, the IRP does not clearly differentiate between EE and DR within its DSM portfolio. With PJM's evolving capacity market rules — such as the implementation of marginal Effective Load Carrying Capability — DR can provide substantial peak shaving benefits. However, the

[19] U.S. Energy Information Administration, Annual Energy Outlook 2024, Transportation Sector. https://www.eia.gov/outlooks/aeo/: EIA's 2024 AEO projects EVs will be 29% of new U.S. LDV sales by 2035, with slower adoption in the Midwest and Southeast regions.

IRP does not identify what portion of DSM is attributed to DR. It also does not disclose peak MW contributions or plans for future DR program development. This raises concerns about the robustness of the DR assumptions used in the model.

While I&M does model DR using bundles derived from the Market Potential Study ("MPS"), similar to how energy efficiency is modeled, those DR bundles are treated as preconfigured packages rather than incremental, modular blocks. As a result, the IRP's optimization process may not fully capture the marginal value of additional DR under alternative system conditions, such as high load growth or capacity shortfalls. More transparency into how these DR bundles are modeled, selected, and constrained would improve the ability to assess the bundles' cost-effectiveness. I&M currently uses DR bundles, distinguished as dispatchable and fixed as mentioned in its MPS. These bundles are incorporated as selectable inputs. In its 2024 IRP, I&M models DR using bundled potential derived from the MPS. However, unlike EE, which is often modeled with more detail across different program years and measure groupings, the DR bundles appear to be larger and less flexible in how they are selected and deployed. The OUCC recommends I&M's future IRPs model DR using smaller blocks (e.g., 25 MW or 50 MW increments), each tied to cost and response characteristics, to allow the IRP model to determine optimal levels and timing of DR deployment. This would allow the resource planning model to better evaluate the value of adding more DR compared to new generation or storage, especially in scenarios with high load growth or tight capacity margins.

Distributed Energy Resources

I&M's IRP includes DER (customer-sited solar batteries and EV charging) as part of the MPS and integrates projected DER volumes into its optimization modeling. However, there is a lack of detail on how I&M plans to operationalize these resources - such as through DER management systems, aggregation platforms, or third-party coordination, to deliver grid services like peak support, voltage regulation, or frequency response. The OUCC recommends future IRPs include I&M's strategy to aggregate and dispatch distributed DERs, including any DER management systems referenced earlier, cost and performance assumptions underlying expected DER contribution to capacity and ancillary markets, and an evaluation of how aggregated DERs compare to other system resources in reliability, cost, and flexibility under high-load or limited supply scenarios.

Rockport Retirement & Environmental Assumptions in Portfolio Selection

The preferred portfolio was selected, in part, because it allowed I&M to better comply with "existing and future Greenhouse Gas regulations based on the current and proposed EPA Section 111(b)(d) rules, and the potential for regulations to occur in some form during the planning horizon."[20] I&M and other utilities need to reassess this in light of the Trump Administration's proposed rulemaking, published on June 11, 2025, to overturn rule 111.[21] The Trump Administration is proposing a complete repeal of greenhouse gas regulation on power plants with no alternative regulation proposed.

Greenhouse gas regulations from a different administration in the future are possible. However, those regulations would be at least six to eight years in the future and would take even longer to implement. Further, in addition to federal regulations, I&M has incentives to reduce greenhouse gases such as AEP's own internal sustainability goals and pressure from major industrial and commercial customers to reduce carbon emissions to enable these customers to meet their sustainability goals. Therefore, I&M should conduct new modeling that projects regulation of

[20] I&M 2024 IRP, 9. 8.3.1 Preferred Portfolio Strategy and Modeling, p.208.
[21] US EPA, Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants, https://www.epa.gov/stationary-sources-air-pollution/greenhouse-gas-standards-and-guidelines-fossil-fuel-fired-power.

greenhouse gases 10 years later than now projected to appropriately adjust to the current regulatory environment.

In addition, to fairly evaluate all potential sources of generation, I&M should broaden its focus beyond carbon, NOx, and SO2 emissions. Levels of CO and volatile organic compound emissions (in terms of pounds per Million British Thermal Units) can be higher for natural gas than coal, and any air pollution permit for proposed natural gas plants will likely need to address these emissions. Water discharge requirements should also be considered, along with waste disposal from wind and solar generation facilities.

IV. Conclusion

The OUCC appreciates the opportunity to review I&M's IRP and participate throughout the stakeholder process. The OUCC also appreciates the opportunity to submit these comments.