Indiana Michigan Power Company

2024 Indiana Integrated Resource Plan

Stakeholder Workshop #1 Meeting Minutes

June 27, 2024

1.) Welcome and Introductions:

Greg Soller covered slide 1

Greg Soller, Indiana Michigan (I&M) Manger of Resource Planning, called the meeting to order at 1:04 PM. Greg welcomed participants to the 2024 Indiana Integrated Resource Plan (IRP) stakeholder workshop and introduced Andrew Williamson, I&M Director of Regulatory Services.

Andrew Williamson covered slides 2-3

Andrew introduced I&M Leadership and the I&M IRP Planning Team who will be conducting the 2024 Indiana IRP internally with engagement and feedback from I&M stakeholders. Andrew also introduced 1898 & Co., who is supporting I&M with stakeholder engagement during the 2024 IRP.

Andrew covered the agenda for the Stakeholder Workshop and introduced Brian Despard, 1898 & Co. Senior Project Manager and moderator for the Stakeholder Workshop.

Brian Despard covered slides 4-5

Brian explained the webinar functionality and presented participation guidelines for the meeting. Relevant stakeholder questions regarding the IRP process were permitted at any time to be answered between sections.

Additional questions and stakeholder feedback related to this meeting were encouraged to be sent to I&MIRP@aep.com. As this meeting was not recorded or transcribed, questions and answers will be provided at the stakeholder website at: Indiana Stakeholder Engagement Process (indianamichiganpower.com).

2.) Stakeholder Meeting Objectives:

Brian Despard covered slide 6

Brian covered the stakeholder meeting objectives: transparency regarding the objectives and assumptions that form the basis of the IRP, and the gathering of productive stakeholder feedback to help shape the IRP.

Stakeholder feedback and input is welcomed on a broad variety of topics pertaining to the IRP, including objectives, market conditions and pricing assumptions, capacity needs, proposed study cases, and more.

3.) Company Overview and Updates:

Andrew Williamson covered slides 7-8

Andrew Williamson presented background on I&M and direction that the company has taken since the last IRP, conducted in 2021. I&M's objectives are to responsibly serve its more than 614,000 retail customers and wholesale customers, while meeting system reliability criteria established by the PJM Regional Transmission Organization.

Andrew also presented I&M's current generation mix. Existing and new generation resources with start terms between 2025-2028 will serve to provide for I&M's immediate needs.

I&M is conducting two 2024 IRPs, one in Indiana and one in Michigan, to serve load in both territories in accordance with differing state policies and needs. The Indiana IRP aims to identify load-serving resources that meet standards set by the Indiana Utility Regulatory Commission's (IURC) "Five Pillars."

4.) 2024 IRP Highlights, Process, & Stakeholder Engagement:

Greg Soller covered slides 9-12

Greg Soller presented on the 2024 Indiana IRP highlights, process, and stakeholder engagement timeline.

Key topics for the 2024 Indiana IRP include discussing relicensing the Cook Nuclear Plant and hydroelectric assets, navigating the transition to state-specific planning, facing challenges brought about by significant future I&M load growth, and recognizing dynamic market conditions that will impact generation for this and future IRPs.

This IRP calls for close coordination between I&M, American Electric Power (AEP), and a diverse group of I&M stakeholders. These three entities, throughout the IRP process, will collaboratively set and modify IRP objectives, market assumptions regarding supply and demand, and portfolio performance criteria.

Agreed-upon inputs will be used to evaluate multiple resource portfolios under multiple market scenarios and sensitivities. Portfolios will be subject to scenario-based risk analysis before a preferred portfolio is selected and a short-term action plan is developed.

Following an IRP Planning Technical Conference for necessary software licensing, today's meeting marks the "official kickoff" of Indiana IRP stakeholder engagement. This is to be followed by three more stakeholder meetings before the 2024 Indiana IRP is submitted in early 2025. The second stakeholder meeting, slated for August-September 2024, will discuss assumptions, inputs, and modeling result drivers. Technical conferences will also be held to analyze modelling inputs and processes more deeply.

5.) General IRP Requirements, 2021 Action Plan, 2024 Commitments:

Greg Soller covered slides 12-14

Greg discussed IRP compliance requirements in Indiana, emphasizing why stakeholder feedback is crucial to this project's success. I&M maintains their obligation to evaluate a broad range of resources to provide a resource mix that aligns with IURC's Five Pillars of reliability, affordability, resiliency, stability, and environmental sustainability.

Greg presents outcomes from the 2021 IRP; I&M secured capacity needed to meet 2024-2025 PJM reliability standards, issued RFPs in 2022 and 2023, and has commenced efforts to evaluate the relicensing of the 2.2GW Cook Nuclear Plant, a cornerstone of I&M's current generation mix. A handful of 2021 IRP outcomes provide a basis for I&M commitments in the 2024 I&M IRP. I&M will evaluate the retirement of Rockport Unit 1 in both 2025 and 2026 as opposed to the 2028 target identified in the 2021 IRP. In addition, I&M commits to modelling their exit from the OVEC Inter-Company Power Agreement (ICPA) in 2030.

For transparency, during the 2024 IRP I&M commits to providing modelling licenses for regulatory stakeholders, publishing a schedule of data releases, and disclosing cost and performance analysis results for energy efficiency and longer-duration storage resources.

6.) Cook and Hydro Relicensing:

Andrew Williamson covered slides 15-18

Andrew Williamson presented an overview of the Cook Nuclear Plant, the importance of the unit to meeting I&M's load, and considerations for relicensing of the plant. Andrew introduced Mohamed Abukaram, I&M Manager of Resource Planning.

Mohamed provided benefits of the unit including massive amounts of carbon-free generation, reliability, and low, stable costs. Andrew also discussed I&M's longstanding financial investment towards keeping Cook operational beyond its current license date.

Mohamed discussed the licenses of U1 and U2 of Cook in 2034 and 2037, respectively. Andrew expressed I&M's obligation to evaluate the economics of Subsequent License Renewal (SLR), and the costs that must be considered in such an evaluation.

Andrew provided an overview of hydroelectric generation along the St. Joseph River System. During the 2024 IRP, I&M will be conducting analysis regarding 40-year renewal on the licenses of Elkhart and Mottville, both set to expire in 2033.

Mohamed informed stakeholders that I&M engaged WSP to assist with evaluation of I&M's hydroelectric assets and potential renewal of Elkhart and Mottville from financial and socio-economic viewpoints.

7.) IURC Pillars,2024 IRP Objectives, & Performance Indicators:

Greg Soller covered slides 20-21

Greg Soller presented the IURC pillars, 2024 IRP objectives, and performance indicators, emphasizing the alignment of primary objectives with proposed metrics and resulting IRP goals. These objectives are crucial for understanding the different dynamics and how they leverage PJM resources to serve customers with the least cost portfolios.

The IRP objectives set by I&M align with the IURC Five Pillars, which are robust and ensure reliability through minimum capacity and market sales. The five pillars are: Affordability, Resiliency, Stability, Environmental Sustainability, and Reliability

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Greg also conducted preliminary discussion of performance indicators for these metrics. I&M strives to set IRP goals that tie directly to each of the five pillars and meet and exceed PJM operating thresholds to maintain a standard of self-reliance.

8.) PJM Update:

Josh Burkholder covered slides 22-25

Josh Burkholder presented updates on the PJM capacity market and interconnection reforms. Throughout 2023, PJM worked on proposals that were eventually accepted by FERC. These updates included an enhanced risk evaluation system that considers various weather and load scenarios throughout the year, which will increase installed capacity reserve margins by roughly 3%.

Josh also explained that PJM will adopt a marginal Effective Load Carrying Capability (ELCC) approach that blends different resources' capabilities during winter and summer, providing a more accurate accreditation of capacity resources.

PJM's new "First Ready, First Serve" interconnection approach, beginning in 2026 will cluster projects ready to proceed, reducing the interconnection queue time to about 18 months from start to finish. This process will undergo transition cycles to manage existing interconnection backlog. The "Retire and Replace" scenarios include MISO's FERC-approved expedited process for interconnection right transfers, which PJM is advocating to adopt similarly.

Preliminary ELCC values for different resource classes over the next ten years were reviewed, providing adjustment factors based on class averages. The updates highlight the importance of improved market structure and capacity analysis, with changes effective for the 2025/2026 Base Residual Auction (BRA). These reforms aim to enhance PJM's capacity market efficiency and interconnection process, ensuring a more robust and responsive system to meet future energy demands.

9.) Capacity and Energy Needs Review (Going-in Position):

Greg Soller covered slides 26-28

Greg presented on the capacity and energy needs, highlighting the implications of Hyperscale Loads (HSL) and the upcoming retirement of significant power plants.

Load growth driven by HSL presents both opportunities and challenges for I&M during the IRP process, as does retirement of the Burkhead Coal Plant by 2028. The implications of Cook license expirations are also essential to recognize for the going-in position, as significant reduction in nuclear capacity between 2033 and 2037 provides for a bigger gap between present and needed energy and capacity.

The stakeholder process must be robust, exploring alternatives to meet energy needs for these considerations and more. I&M seeks to not only secure capacity and energy to meet PJM requirements but exceed them to mitigate future uncertainties. Greg emphasized the importance of solutions and strategies for transitioning from coal and other capacity-only purchases that will cease by 2028. Planning beyond minimum reserve margins is necessary to manage risks and uncertainties.

10.) IRP Fundamentals: Market Scenarios and Base Assumptions:

Mark O'Brien covered slides 30-34

Mark O'Brien presented the IRP fundamentals covering market scenarios and base assumptions. Currently, scenarios include high, base, and low market conditions as well as an Enhanced Environmental Regulation (EER) scenario which utilizes proposed EPA 111d Rule Changes and would affect coal and gas units, both new and existing. The goal of the discussion is to form a basis of understanding for the varying market and regulatory conditions that may impact the optimal resource mix.

Market conditions considered during scenario selection include load growth and gas prices. Mark presented on anticipated PJM Generation Mix, which followed some base assumptions across all scenarios, such as coal replacement via natural gas and hydrogen blends. Solar growth across PJM is significant in all scenarios, with moderate growth for wind. Gas prices reflect demand across differing mixes of natural gas utilization and account for WTI prices and LNG imports.

Finally, Mark presented PJM market prices which are driven primarily by gas supply and demand, and sharply increase for the EER case to reflect EPA policy changes and expiration of certain beneficial credits.

11.) Technology Alternatives and Resource Timing Strategies:

Greg Soller covered slides 35-36

Greg Soller presented the discussion on technology alternatives and resource timing strategies, categorized into three major areas: gas resources (intermediate and peaking), renewable and storage, and advanced generation.

The presentation emphasized that gas resources provide essential capacity and energy as needed, while intermittent storage needs to be expanded to support proposed renewables. Advanced generation, such as small modular nuclear reactors, is attracting public attention, though costs are yet to be fully determined. Given Indiana's rapidly increasing capacity and energy needs, reliance solely on newbuilds is impractical, making pre-existing assets crucial through power purchase agreements (PPAs) and other contracts.

Potential timing strategies were explored, with a significant focus on leveraging existing assets to meet near-term needs, which will be discussed in detail in the second stakeholder meeting. Request for proposals (RFPs) will be conducted for mid- to long-term resources, while self-development and strategic partnership remain viable options.

The value of renewable and storage options was highlighted, including the benefits to customers and potential tax advantages. Considerations for small modular reactors were also discussed.

12.) IRP Proposed Cases and Sensitivities:

Greg Soller covered slides 37-40

Greg Soller discussed the IRP's proposed cases for analysis of portfolios under different market and demand conditions, as well a case that includes Enhanced Environmental Regulation, for which assumptions were reviewed and will be provided to stakeholders.

Greg also discussed sensitivities to be applied to modelling efforts, such as low and high load scenarios for Indiana with the outlying market remaining stable. Other base case derivatives included Phase 2HSL additions and scenarios with the 2024 EPA 111(d) Final Rules.

Finally, Greg revisited previous discussion on special sensitivities I&M is committed to analyzing, including 2025/2026 Rockport requirements and the removal of OVEC resources by 2030.

13.) Proposed Portfolio Performance Metrics:

Greg Soller covered slides 42-47

Greg outlined the proposed portfolio performance metrics aligned with IURC's five pillars of affordability, reliability, resiliency, grid stability, and sustainability. The proposed scorecard and matrix was analyzed according to these pillars to ensure a comprehensive evaluation.

Affordability was proposed to be examined in both near- and long-term scenarios under a base case, with an emphasis on a slower growth rate in the near term and its impact on deferred decisions and long-term implications. Per I&M, evaluation should also consider the risks and customers face if market conditions change after decisions are made.

Resiliency was proposed to be measured using the Shannon-Weiner index, summing capacity and energy diversity indices for 2033 and 2044. This index provides for equal value weighting for capacity and energy to reflect the value of dispatchable nameplate capacity.

Grid Stability should be quantified in a way that recognizes the necessity of addressing system stability through ISO management, dispatch, and load balancing, considering thermal and storage options.

Sustainability's guiding metrics should measure the impacts of portfolios on reducing CO_2, NO_x, and SO_2 emissions, weighing these reductions against the associated costs for consumers in I&M's service footprint. Emphasis was placed on the balance between consumer desires and delivery costs, evaluating the percent change from 2005 to understand the implications in different portfolios (Slide 47).

14.) Final Questions, Discussion, Action Items, and Adjourn

Brian Despard covered slide 48

APPENDIX A – QUESTIONS VERBALLY ASKED AND ANSWERED DURING MEETING #1

Question	Response
I&M had a planning technical conference in early June with certain stakeholders, is that correct?	Yes, we met with CAC and OUCC about some of the DSM and energy efficiency inputs that have been part of other agreements and commitments we have made.
What will be the cadence of technical/confidential stakeholder meetings? We want those to be at a regular cadence aligned with the public stakeholder meetings. Typically, we have a technical meeting with those with NDAs before each public meeting.	There is no cadence yet, there needs to be flexibility and we do not want to put any hard dates in. The technical meetings will be with the stakeholders working with modeling licenses.
Registering for meeting website said there would be separate meetings for Michigan and Indiana. Will I&M be holding stakeholder meetings jointly with both states going forward?	Beginning with this IRP, I&M is transitioning to a state-specific integrated resource planning model. This is an important change that has been given significant consideration. The change will allow I&M to tailor its future resource plans and decision to the needs and energy policies specific to each individual state which will best position I&M to meet the ongoing needs of its customers and comply with state energy policies. I&M has had several conversations with both state commissions and other stakeholders to discuss the importance and value associated with this change. This meeting is the beginning of the 2024 IRP for Indiana and the 2024 IRP for Michigan is expected to begin in the August/September time frame.
Follow up from above question: Does this mean that Indiana and Michigan are splitting into separate LSEs?	No, that will not be necessary. What this change means is that we will be evaluating our future resource needs and tailoring a preferred resource plan or portfolio to meet those needs on a state-specific basis. In the future, resources will be acquired specific to that states needs and consistent with that states IRP to best position I&M and its respective state commission to ensure reliability and resource adequacy for customers, as well as compliance with each state's unique energy policies.

Question	Response
Follow up from above question: How does this work in practice? How are you going to manage cost allocation for units you own, does this change in some way compared to previous IRPs?	Our plan is for the cost allocation of current resources to remain consistent with current practices and past IRPs. As an example, the IRP is using the most recently allocation factors for its going in resources. I&M will be making future filings with both state commissions to address cost allocation for current resources as needed. However, future resources would expect to be specific to one state and therefore the costs will be fully assigned to that state, which in many ways simplifies the cost allocation process.
Follow up from above question: Why is I&M conducting IRPs for a Multi-State company in different states? This seems to limit the impact the state of Michigan has because so much of the load is in Indiana. Could you explain why this change is better and why it makes sense for rate payers?	The impact that Indiana or Michigan have on future resources decisions will be directly influenced by each states load and resource needs. This change best positions I&M to ensure the future resources it seeks approval of from either state align its respective energy policies. This alignment is important and makes of sense since the energy policies of a given state apply to the retail load within that state. Additionally, today Indiana represents more than 80% of the retail load I&M serves and that percentage will continue to grow as I&Ms Indiana retail load grows considerably over the next several years. The significant load growth in Indiana will require a significant amount of additional generation resources in the future and it's important that Indiana has the oversight and control over ensuring those resources are approved to serve that load growth in Indiana. This change means that as we make resources decisions in the future, we can tailor these decisions to one state or the other while not requiring one state to flex to the other states energy policies or be resource needs.

Question	Response
Following the above question: It will be important to figure out how to address cost allocation for each state. As an example, let's say your Michigan plan retires a unit. Is the assumption that the cost of that unit is then borne by Indiana rate payers?	Cost allocation is not expected to be an issue. There are plans in place to replace Rockport. We have already made the necessary resource approval filings in Indiana and will file for approval in Michigan in July. The next major retirement that is a possibility is the Cook Nuclear Plant. The Cook relicensing decision will be a focus of both the Indiana and Michigan 2024 IRPs and the decision is expected to be consistent across both states despite being modeled independently. As mentioned previously, the IRP will model Cook on a state-specific basis consistent with the current allocation of Cook to each respective state. I&M does not envision there being a situation where you have a resource plan related to existing assets where there is a retirement of a facility in one state, but not in the other.
Could you help me understand some of the data center aspects. What portion of this load growth is data centers that have been publicly announced versus data centers that are expressing interest and are less firm? What are the milestones, from initial conversation to final decision, to confirm that the data center load growth is real?	Slide 26 represents the summation of loads that I&M has interconnection agreements in place or in development. Approximately 75% of the load shown has been publicly announced, the rest are yet to be announced. Based on what we know today, there is confidence that the load as shown will materialize over this period but there may be differences in timing and the amount of load that materializes in a given year.
Follow up from above question: What kind of protections are there for consumers? If there are large investments being made for these data centers how will you ensure that there is not a cost shift if the data centers shut down early? This seems like a tremendous risk to existing customers if I&M overestimates how much load growth will occur. What assurances or protection do consumers have in place to protect them from that outcome?	I&M is in the process of preparing a filing to modify its industrial power tariff to propose a consistent set of terms and conditions of service that would apply to large load customers to better address and balance risk. These changes include higher minimum billing demands, longer contract terms, credit requirements and charges if a customer would significantly reduce its load or cease operation during the contract period. These changes will better position I&M and all of its customers to have a better set of protections in place to address unforeseen events that could occur in the future. I&M has plans to make that tariff filing relatively soon.
Discussion of metrics: "These are the metrics we will use"- Does that mean that those metrics are final?	No, these are proposed Metrics for this first Stakeholder Meeting. We will look to reconcile feedback to the metrics following Stakeholder Meeting 2.
Could you provide info for stakeholders who have not heard the index term before; the way you measure generation diversity through an index? Can you provide an example of how that calculation works?	The Shannon-Weiner index is proposed for the Diversity metric. Information on this index is available on the internet to get more understanding. In summary, the index considers the number of different types of resources and their contribution towards the total.

Question	Response
Follow up from above question: When you say you are counting the number of slices of pie along with the size of each slice, does that mean that each generator, regardless of technology type, counts as a slice of pie, and that the measure of that generator's contribution will be its firm capacity?	The firm capacity of each generator type is going to be looked at. We will also evaluate the energy index by generator type
Follow up from above question: Do you have a draft load and peak forecast that you can share with us?	Load and peak forecasts, there will be a data release for the PLEXOS side of modelling with peak and energy demand forecasts.
Regarding the Capacity Needs Assessment (Slide T28) and Energy Needs Assessment (Slide T28), (i) does this include I&M's current wholesale commitments with the needs (aka 12.6% of I&M load), (ii) what are the types of "wholesale" customers within this category and (iii) since this is focused only on Indiana only, how are capacity assets across Michiana and Indiana reflected against the needs?	Capacity needs and energy needs does include I&M's wholesale commitments. Capacity assets will be allocated based on the respective IN and MI wholesale jurisdictional allocations.
Why are you using the proposed EPA Rule rather than final rule?	With the final rule, no fully prescribed treatment for existing natural gas exists. It does have an emission limit that they need to stay under, but there isn't any treatment like retrofitting carbon capture and sequestration or various types of fuel blend that are explicitly stated under that scenario. So we see the proposed rule as being more aggressive and something that's probably a bit more likely to occur as the EPA develops the rules over the next year or so for existing natural gas plants.
Where does the hydrogen come from in your simulations? It did not appear that renewables increased significantly in the later year your slide was showing.	Blue hydrogen is assumed to be the hydrogen source. The forecasted cost of blue hydrogen is generally lower than green hydrogen production. Blue hydrogen relies upon the mature steam methane reformation process and natural gas is readily available as a feedstock. The higher marginal cost of green hydrogen production is due to the more expensive and relatively new hydrolyzer technology.
Following the above question: Could you provide these pricing inputs?	Yes, the hydrogen forecasts will be provided to Stakeholders.
Following the above question: Why would only behind-the-meter renewables be used to make hydrogen?	For clarification, behind the meter generation is assumed for green hydrogen production. To maximize the return on investment via credits, green hydrogen producers are assumed to produce hydrogen with all available renewable generation available to them each hour. This assumption is further supported by the IRS' proposed treatment to qualify for green hydrogen credits. The IRS has proposed that a facility

Question	Response
	will only qualify for green hydrogen credits if new renewable generation is installed. Additionally, the IRS has included stipulations of hourly matching of credits with hydrogen production and are proposing that the renewable power and hydrogen production be within the same geographic region.
Greg, we'd like to provide feedback on the scenarios and sensitivities as well, but it's not possible to do that in a vacuum, e.g., I don't know what "base" technology costs means. Will you be providing all this data so we can review and comment?	Yes, all that information will be given to stakeholders. We will be working on the release schedule of the data and inputs as we go forward with the technical stakeholder meetings.
Following the above question: EIA capital cost assumptions: Do those approximate the inputs you are using?	No, the Company has found through its RFPs that EIA benchmark costs are a bit low. While we start with EIA as a baseline, capital costs are updated with insights from our RFPs.
Slide 45-Relationship between Pillars and metrics; how do you translate pillars into metrics? Stability is a balance (not too much not too little). Stability challenges and how to measure it. Will the metric measure what type and how much of stability services each resource offers? Would the portfolios need to satisfy some minimum amount of stability services?	One of the things that doesn't really occur in the IRP is location-specific sitting. The IRP identifies resources to support the Company's capacity position, but those resources include different operational characteristics that provide grid stability attributes available to PJM to effectively manage the grid.
Follow up to the above question: I appreciate the challenge. My thought here is not that you're going to undertake some sort of transmission planning study or even a generator retirement study in conjunction with IRP. I'm suggesting that you use the analysis that your transmission planners have done to help inform the grid needs that you're already aware of. I think that's a really helpful starting place as you think about replacement generation in particular and also to also understand where new generic resources could be located as well. You know where violations are and your system right now, you know where you might need to make some sort of change to operations or change to lines would be very helpful information.	The Company appreciates this feedback and will review it with its Transmission Planning team.