Draft Director's Report

For Indiana Michigan Power Company's 2021 Integrated Resource Plan

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on behalf of the Indiana Utility Regulatory Commission

TABLE OF CONTENTS

Draft Director's Report Applicable to I&M's 2021 Integrated Resource Plan and Planning Process

I. Purpose of IRPs

Indiana Michigan Power Company's (I&M's) 2021 Integrated Resource Plan (IRP) was submitted on Jan. 31, 2021. By statute and rule, integrated resource planning requires each utility that owns generating facilities to prepare an IRP and make continuing improvements to its planning as part of its obligation to ensure reliable and economical power supply to the citizens of Indiana. A primary goal is a well-reasoned, transparent, and comprehensive IRP that will ultimately benefit customers, the utility, and the utility's investors. At the outset, it is important to emphasize that these are the utilities' plans. The Research, Policy, and Planning (RPP) Director in the report does not endorse the IRP nor comment on the desirability of the utility's "preferred resource portfolio" or any proposed resource action.

The essential overarching purpose of the IRP is to develop a long-term power system resource plan that will guide investments to provide safe and reliable electric power at the lowest delivered cost reasonably possible. Because of uncertainties and accompanying risks, these plans need to be flexible, as well as support the unprecedented pace of change currently occurring in the production, delivery, and use of electricity. IRPs may also be used to inform public policies and are updated regularly.

IRPs are intended to be a systematic approach to better understand the complexities of an uncertain future, so utilities can maintain maximum flexibility to address resource requirements. Inherently, IRPs are technical and complex in their use of mathematical modeling that integrates statistics, engineering, and economics to formulate a wide range of possible narratives about plausible futures. The utilities should utilize IRPs to explore the possible implications of a variety of alternative resource decisions. Because of the complexities of integrated resource planning, it is unreasonable to expect absolutely accurate resource planning 20 or more years into the future. Rather, the objective of an IRP is to bolster credibility in a utility's efforts to understand the broad range of possible risks that utilities are confronting. By identifying uncertainties and their associated risks, utilities will be better able to make timely adjustments to their long-term resource portfolio to maintain reliable service at the lowest reasonable cost to customers.

Every Indiana utility and stakeholder anticipates substantial changes in the state's resource mix due to several factors and, increasingly, Indiana's electric utilities are using IRPs as a foundation for their business plans. Since Indiana is part of a vast interconnected power system, Indiana is affected by the enormity of changes throughout the region and nation.

The resource portfolios emanating from the IRPs should not be regarded as being the definitive plan that a utility commits to undertake. Rather, IRPs should be regarded as illustrative or an ongoing effort that is based on the best information and judgment at the time the analysis is undertaken. The illustrative plan should provide off-ramps to give utilities maximum optionality to adjust to inevitable changing conditions (e.g., fuel prices, environmental regulations, public policy, technological changes that change the cost effectiveness of various resources, customer needs, etc.) and make appropriate and timely course corrections to alter their resource portfolios.

II. Introduction and Background

I&M's Preferred Portfolio in its 2021 IRP is centered on a clearer vision of the treatment of both Rockport units. The preferred plan focuses on the need for replacement resources prior to 2028, with decisions beyond 2028 to be based on the potential license extensions of the Cook Nuclear Plant. The Preferred Portfolio assumes Cook Unit 1 and Unit 2 operations continue through 2034 and 2037, respectively. The Preferred Portfolio includes 800 MW of wind, 1,300 MW of solar, and 1,000 MW of gas peaking capacity through 2028.

From the Director's perspective, I&M, like most utilities across the United States, is addressing resource changes in an environment of extreme uncertainty regarding government policy, commodity prices, and technology. To better address these uncertainties, the 2021 IRP included a couple of significant changes compared to the 2018 IRP.

- I&M used a Market Potential Study (MPS) developed by GDS Associates and Brightline to evaluate the potential for future energy efficiency (EE), demand response (DR), and distributed energy resources (DER).
- I&M contracted with Siemens PTI to provide expertise and perspective, facilitate the public advisory process, and support the modeling and development of the IRP report.

Consistent with the issues discussed above, the Director's report will focus on three broad areas: (1) load forecasting; (2) assessment of demand-side resources broadly defined to include energy efficiency, demand response resources, electric vehicles, and other distributed energy resources (DERs); and (3) portfolio analysis and the consideration of risk and uncertainty on different resource portfolios.

III. I&M Load Forecast

I&M serves approximately 471,000 retail customers in Indiana and 130,000 retail customers in Michigan, respectively. The peak load requirement of I&M's total retail and wholesale customers is seasonal in nature, with distinctive peaks occurring in the summer and winter seasons. I&M's all-time highest recorded peak demand was 4,837 MW, which occurred in July 2011; and the highest recorded winter peak was 3,952 MW, which occurred in January 2015. The most recent (summer 2020 and winter 2020/21) actual I&M summer and winter peak demands at the time this process began were 3,970 MW and 3,365 MW, occurring on July 19, 2020, and Feb. 17, 2021, respectively.

Over the next 20-year period (2022-2041), I&M's service territory is expected to see population and non-farm employment growth of 0.0% and 0.4% per year, respectively. Not surprisingly, I&M is projected to see customer count growth at a similar rate of 0.1% per year. Over the same forecast period, I&M's retail sales are projected to grow at 0.3% per year with stronger growth expected from the industrial class (+0.46% per year) while the residential class experiences 0.3% compound annual growth rate (CAGR) and the commercial class remains relatively flat over the forecast horizon. Finally, I&M's internal[1] energy and peak demand are expected to decrease at an average rate of 0.5% and 0.3% per year, respectively, through 2041.[2]

[1] The load forecasts prepared by I&M reflect the traditional concept of internal load, i.e., the load that is directly connected to the utility's transmission and distribution system and that is provided with bundled generation and transmission services by the utility.

[2] The forecast developed by I&M does not assume the automatic renewal of expiring wholesale contracts. This assumption results in significant load drops in the 2030s.

The above forecast results are based on I&M's base case load forecast. I&M recognizes there are a number of known and unknown potentials that could drive load growth different from the base case. To frame the possible outcomes, I&M developed forecast sensitivity scenarios tied to respective high and low economic growth cases. The high and low economic growth scenarios are consistent with scenarios presented in the U.S. Energy Information Administration's (EIA's) 2021 Annual Outlook. The economy is seen as a crucial factor affecting future load growth.

For I&M, the low-case and high-case energy and peak demand for the last forecast year, 2041, show deviations of about 14% below and 17% above, respectively, the base-case forecast. These spreads in the last forecast year have a larger range than the 2018 IRP, which reflects the increased uncertainty in the load forecast.

I&M prepared other load forecast scenarios. The key take away is that these alternative load forecast scenarios fall within the low and high economic scenario forecasts. I&M states that any reasonable load forecast will fall within the low and high range.

I&M does not explicitly adjust the load forecast for increased adoption of EVs. I&M monitors the adoption of EVs and will address the issue as it becomes more significant.

According to I&M, the current levels of customer self-generation (net metering and combined heat power) are not "overly impactful" compared to I&M's total system load. I&M's load forecast methodology captures the historical trends and assumes a continuation of this trend in customer self-generation load. The impact of incremental customer self-generation (meaning above the historical trend) is not included in the load forecast.

DIRECTOR'S COMMENTS – Load Forecast

I&M's forecasting methodology appears to be reasonable and sound overall and has not changed in any significant way since the 2018 IRP. Load over the planning horizon is a large and significant source of uncertainty for any electric utility, given the potential for changes driven by EV adoption, the spread of DERs, and the likely increasing electrification of end-use consumption across customer classes. I&M recognizes this by developing several different load forecasts that are bounded by a high economic growth and a low economic growth scenario. These uncertain drivers are not likely to cause large changes in load over the next several years, but longer term the potential is considerable.

However, it appears that all 14 portfolios are based on the base load forecast, including the three optimized scenarios. No optimized scenario appears to have been based on a high- or low-load forecast. The Director recognizes that the impact of higher load, for example, will play out over time with relatively small impact on resource choices over the next few years. Nevertheless, it would have been informative to understand how sensitive the level of resources to be acquired over time is with different load forecast assumptions.

Some additional thoughts:

1. I&M states that the long-term residential models are 30-year monthly models that are driven by economic and demographic variables. It seems unlikely that projections for explanatory variables are available (or would be credible) on a monthly basis for 30 years. It seems more likely that the models use annual projections, and the monthly forecast is

derived from the annual numbers. I&M uses binary variables to capture monthly variations in customers. *(See I&M IRP, Customer Forecast Models, pp. 36 -37)*

2. I&M states that weather drivers are assumed to be normal for the forecast period, but they do not state what was used for normal weather. *(See I&M IRP, p. 43)*

3. I&M for this IRP presented several load forecast scenarios with different adjustments (e.g., No new DSM, EE 2021 scenario, EE extended scenario, Base case, etc.) What are the benefits of considering these various load forecast adjustments? How were these forecasts used? Were the forecasts developed to provide a better understanding of the sensitivity of the load forecast to changes other than for high and low economic growth?

IV. I&M DSM

Summary and Overview

In the 2021 IRP, the I&M's residential and commercial usage model was estimated using a Statistically Adjusted End-Use model (SAE) which was developed by Itron. These models were used to account for changes in the saturations and efficiencies of the various end-use appliances to prevent double counting the impacts from the I&M sponsored energy efficiency (EE) programs in the load forecast. According to I&M, every three to four years the Company conducts surveys to monitor the penetration, saturation, and age of the various appliances in the residential home. This information was then matched up with future appliance saturation and efficiency projections modeled by EIA. The result of this approach was that I&M's 2020 end-use base load forecast for use in the Market Potential Study (MPS) already includes some significant reductions in usage because of projected trends of energy efficient technologies.

To align the sales forecast used in the MPS with the assumed savings opportunities, the GDS Team developed an adjusted "code frozen" forecast that permits the existing equipment stock to improve and meet, but not exceed, legislated federal minimum standards. The result is a sales forecast that is higher, over the 20-year horizon, than I&M's base sales forecast used in the IRP. For another adjustment, GDS excluded commercial or industrial customers with a peak load greater than 1 MW that had opted out from EE programs from the estimates of future electric EE potential. Furthermore, a small number of industrial sales were moved to the commercial sector to better align commercial vs. industrial savings opportunities in the MPS modeling.

The MPS provided an update of demand-side management (DSM) programs, measures, program costs, participants and kWh and kW savings potential for the period 2023-2042 and historical savings, and projected energy and demand savings opportunities to develop estimates of EE and demand response (DR) technical, economic, and achievable potential.

For this 2021 IRP, differently than in the 2018 IRP, I&M engaged Siemens PTI to support the modeling and development of the IRP report. The GDS Team and Siemens PTI utilized the information from the MPS for modeling future DSM resources and to develop the measure list and then the EE Bundles. In total, 353 unique EE measure types were analyzed for this study. Several measures were included with multiple permutations to account for specific market segments, such as different building types, efficiency levels, and replacement options. Furthermore, for this IRP there is the inclusion of transmission and distribution (T&D) avoided costs with DSM resources.

The EE bundles for modeling were developed using a statistical process, known as "k-means clustering", to determine the number of bundles and which measures to assign to individual bundles. A set number of bundles was defined for the process of assigning each EE measure to one of the bundles. The net present value (NPV) benefits and costs per lifetime kWh savings for each EE measure were used to cluster the measures into bundles. Five residential bundles, one income-qualified bundle, and eight commercial and industrial (C&I) bundles were identified and were used as IRP inputs. These IRP inputs were classified across three different vintage bundles: 2023-2025, 2026-2028, and 2029-2040. The EE MWh and MW impacts for each vintage block provided the cumulative annual lifetime savings. Based on the measure-bundle assignment, the program potential savings were mapped from the MPS into the identified EE bundles for IRP model input.

The AURORA model was the software used to sort through the diverse mix of potential resource combinations and return an optimum solution, instead of Plexos, which was utilized in the 2018 IRP. I&M models demand-side resources in Aurora as non-dispatchable "generators" such as wind or solar. Thus, the value of each resource was impacted by the hours of the day and time of the year that it generates energy. In addition to the annual impacts, typical hourly (8,760) shapes for each EE bundle were used to assess the value of energy savings on an hourly basis. The EE bundle savings were disaggregated based on the same end-use load shapes utilized in the MPS; therefore, the shapes were unique for each EE sector and vintage bundle. Then, the optimization model selected optimal levels of incremental economic EE, based on projections of future market conditions, the future expected costs of available supply resources, and the level of available incremental EE.

Two adjustments to the MPS's program EE potential savings, and one direct adjustment to costs, were performed prior to inclusion in the IRP. The first adjustment was to provide the program potential savings at the generator level because the MPS savings are at the meter. The second adjustment was to align the projections of the future EE potential with the embedded efficiency trends already included in the I&M load forecast, referred to by I&M as the Supplemental Efficiency Adjustment (SEA).

The resulting total annual IRP's EE program savings contains both the ongoing impacts from current programs and the optimized levels of EE from the IRP optimization process. Based on the settlement in Cause No. 45546, IRP assumptions included the development of additional sensitivities to evaluate the effect of applying a Net-to-Gross (NTG) Energy Efficiency adjustment to the EE bundle potential savings in place of the previously described SEA.

Energy Efficiency (EE) Resources

The amount of available EE was described from four perspectives: technical, economic, achievable, and program potentials. The economic potential for EE included measures that were identified as cost-effective based on screening with the Utility Cost Test (UCT). As part of the UCT, I&M considered electric energy, capacity, and transmission & distribution (T&D) savings as benefits, and utility incentives and direct install equipment expenses as the cost. The measure level economic screening did not consider non-incentive/measure delivery costs (e.g., administration, marketing, evaluation etc.) in determining cost-effectiveness. Low-income measures were not required to be cost-effective.

The potential study evaluated two achievable potential scenarios: Maximum Achievable Potential (MAP) and Realistic Achievable Potential (RAP). Then, the RAP was refined into the Program Potential based on the following updated factors: incentive levels and structures, program non-incentive costs (e.g. administration), and measure assignments (e.g. reassignments to new program types). Finally, the non-income qualified EE programs were modeled on a comparable economic basis as supply-side programs in the IRP.

Demand Response (DR) Resources

I&M has two customers with interruptible provisions in their contracts and 135 customers for interruption in emergency situations in DR agreements. The IRP's load forecast did not reflect any load reductions for these customers. Rather, the interruptible load was seen as a resource when the Company's load is peaking. As such, DR programs are accounted for as a load shape reduction from the load forecast used in the IRP.

DR potential for the I&M territory was estimated following a similar methodology as the EE analysis. For this, technical, economic, and two achievable scenarios (maximum and realistic) were developed considering the potential for 23 different DR program iterations. Levels of DR potential for summer peak demand reduction associated with RAP and MAP scenarios were provided as inputs to the IRP. Each scenario's reductions were divided into two bins based on resource type, whether a dispatchable or callable, DR resource or a fixed DR resource. Time-of-use rate programs make up the only fixed DR resource in the RAP and MAP scenarios. All other programs in the scenarios were dispatchable resources.

For this IRP, DR programs received a non-optimized treatment within the AURORA model which means that the capacity was included as going-in resource. However, the actual impact to each portfolio depends on the economic dispatch of the program. Also, the DR programs were modeled for three continuous hours for I&M's top five days of demand, totaling 15 hours each year. Given the non-optimized treatment the economic benefit of these programs is not evaluated in the IRP analysis.

Distributed Energy Resources (DER)

DERs were modeled based on residential and non-residential solar photovoltaic (PV) and non-residential combined heat and power (CHP) resources. Potential for both resources was assessed based on premise-level availability to host the DER technology across the I&M service territory with economic analysis using estimated market costs and generation benefits to the end-use customer. I&M estimated customer penetration based on diffusion curves informed by existing installed systems, assumed maximum market penetration, and coefficients of innovation and imitation. The innovation and diffusion coefficients were based on state-specific research done by NREL. The forecast evaluated the level of PV and CHP installations over the 20-year MPS planning horizon.

The DER analysis found that all modeled PV and CHP resources were not cost-effective using the Total Resource Cost (TRC) test. Given this result, no achievable market potential for DERs was evaluated.

GDS, however, performed additional modeling based on a business-as-usual scenario to understand how future DER growth may occur in the I&M service territory with no intervention by I&M. This was done by using data on the willingness to adopt DER without any utility incentive. The resulting forecasted incremental DER was added to the existing DER capacity and included in all Candidate Portfolios. It is important to note that the IRP analysis took the DER as a part of the resource portfolio, meaning the DERs were not optimized.

Avoided Costs

The avoided costs developed by I&M for the MPS included avoided capacity costs, avoided T&D costs, and avoided energy and operating costs. The inclusion of avoided T&D costs was new for the current MPS and IRP.

The avoided capacity costs are from I&M's fundamentals forecast as the proxy estimate for the marginal cost for capacity in the PJM market.

I&M's avoided energy and operating cost included fuel, plant operation and maintenance, spinning reserve, and emission allowances, excluding transmission and distribution losses. Scenario on- and off-peak power price forecasts were a modeling output produced by the AURORA dispatch model informed by scenario input assumptions, along with a view of the greater PJM market.

For avoided T&D costs, an I&M system level estimate of $20 per kW-year was applied to DSM resources in the MPS analysis. This estimate represents I&M's valuation for any localized benefits that may be realized from T&D system capital deferrals resulting from EE, DR, and DER. The estimate is based on work performed by I&M and Accenture in 2020. According to I&M, the $20 per kW-year for avoided T&D is within industry ranges and appropriate for I&M's specific circumstance.

DIRECTOR'S COMMENTS – DSM

The Director appreciates the collaborative effort used by I&M and GDS Associates to develop the MPS. Based on comments by other stakeholders, it is clear that I&M and GDS listened to the suggestions provided by the other stakeholders and included a number of suggestions into the MPS development process. Also, the Director supports I&M's inclusion of avoided T&D costs in the MPS evaluation of DSM measures and the IRP modeling.

<u>Questions</u>

- The EE savings estimated with the Net-to-Gross EE bundle approach show higher EE capacity additions in the alternative portfolios for the period 2029-2041 than in the reference case portfolio that uses the SAE factor approach. Since there were already some refinements applied to the original Reference Case to get the Preferred Portfolio, why not consider the addition of more savings identified with the NTG approach? Why was the NTG approach not the main approach to be used for all the portfolios instead of the SAE approach?
- What drives the decline of the EE capacity expansion plan of the Preferred Portfolio and other alternative portfolios beyond 2034 (Exhibits C-1 through C-16)? Is it expected the EE programs to achieve their cumulative maximum capacity savings in that year?
- What is the reason for the DSM/EE energy and demand savings to decline to zero by 2037 (Exhibit A-12) and then show an increase in savings starting in 2038? A similar pattern is observed with the summer and winter demand savings. Furthermore, the demand savings do not seem to change consistently with the increase/decrease of the DSM/EE energy savings numbers.
- In the IRP optimization, did I&M test the use of the levelized EE program costs over the bundle life so the costs are on equal basis with supply-side resources? Or are the EE costs being analyzed as incurred (in year one), and does this represent a fair comparison to all other competing resources?
- Why did all the DR programs receive a "non-optimized" treatment (Table 17, Page 120) in the IRP modeling process (Aurora)?

V. I&M Scenario/Risk Analysis

Models

AURORA is the primary modeling application used by Siemens PTI for identifying and analyzing portfolios that address the gap between resource needs and current available resources. The model uses hourly chronological dispatch over a 20-year period which helps to better evaluate intermittent and storage resources. The long-term capacity expansion (LTCE) functionality within AURORA was used to develop least cost optimized portfolios based on the given sets of market input assumptions and portfolio requirements. The LTCE function drives build, retirement, and purchase decisions for the resulting portfolios.

Method

I&M followed a 5-step approach to develop the IRP on which the Preferred Portfolio is based.

Step 1 - Determine Objectives
The initial step is to determine the objectives to be used to evaluate the Candidate Portfolios.

Step 2 – Identify Metrics
Assign metrics to the objectives established in Step 1. The metrics are used to measure and evaluate performance of the portfolios in the probabilistic simulations done in Step 4.

Step 3 – Create Candidate Portfolios
Create a set of optimized portfolios under a set of inputs that are informed by conditions. These conditions are a unique combination of scenarios and sensitivities used to inform Candidate Portfolio development.

Step 4 – Analyze Candidate Portfolios
Conduct portfolio analysis to determine cost and performance metrics for each portfolio. The primary tool for portfolio analysis was a probabilistic method.

Step 5 – Scorecard and Report
The final step is to review detailed portfolio results through a scorecard that measures the attributes of the different portfolios against IRP objectives.

Three scenarios were constructed in this IRP: the Reference scenario, the Rapid Technology Advancement (RTA) scenario, and the Enhanced Regulation (ER) scenario. Candidate Portfolios were first developed utilizing AURORA's LTCE modeling for the Reference Scenario, the RTA scenario, and the ER scenario by optimizing resources based on lowest cost. In addition to the optimized portfolios, additional portfolios were identified to specifically test alternative resource strategies. These included defined portfolios in the I&M settlement agreements for Cause No. 45546, along with portfolios identified by I&M to evaluate resource selections related to different future assumptions pertaining to the Cook nuclear unit life extension, as well as evaluating solutions with high amounts of renewable resources. There were 14 candidate portfolios in total, which are briefly described in the following table.

Table 4. Reference and Candidate Portfolios

Scenario Name	Portfolio Name	Description
Reference	Reference Case (Original)	Rockport Unit 1 (2028) Rockport Unit 2 (2024) and Cook (2034, 2037)
Reference	Rockport 1 2024	Rockport Unit 1 Early Retirement (2024)
Reference	Rockport 1 2025	Rockport Unit 1 Early Retirement (2025)
Reference	Rockport 1 2026	Rockport Unit 1 Early Retirement (2026)
Reference	Cook 2050+	Cook Unit 1 and Unit 2 License Extensions (beyond 2034 and 2037)
Reference	Cook 2050+ and No Gas	Cook Unit 1 and Unit 2 License Extensions and No Conventional Gas
Reference	Expanded Build Limits	Expanded Cumulative Build Limits on Renewable Energy and Storage
Reference	Reference' ("Prime")	Reference Case (Original) with an Import and Export Limit at ~30% of I&M Load
Rapid Technology Advancement	Rapid Technology Advancement	35% Reduction in Renewable, Storage and EE Costs
Enhanced Regulation	Enhanced Regulation	Increased Environmental Regulations Leading to High Gas, Coal and CO_2 Prices
Reference	Rockport 1 2024 N2G	Rockport Unit 1 Early Retirement (2024) Replacing SEA with Net to Gross EE Bundle Savings
Reference	Rockport 1 2026 N2G	Rockport Unit 1 Early Retirement (2026) Replacing SEA with Net to Gross EE Bundle Savings
Rapid Technology Advancement	Rapid Technology Advancement N2G	Rapid Technology Advancement (RTA) Replacing SEA with Net to Gross EE Bundle Savings
Reference	Reference with No Renewable Limits	Removed cumulative Build Limits on Renewable Energy and Storage

(p. 23 of I&M IRP Report)

Probabilistic modeling begins with the simulation of 200 sets of future pathways for coal prices, natural gas prices, carbon emission prices, peak and average load, and capital costs for a range of technologies. Each of the stochastic variables is propagated though the planning period, typically over 2,000 times. A stratified sampling of the runs is taken, allowing the sample set to be reduced to 200 iterations. All 14 Portfolios were subjected to each of the 200 iterations using AURORA in dispatch mode where the I&M portfolio is fixed but other PJM members can make decisions under each market scenario. Such analysis provided an assessment of how the 14 portfolios performed under a range of market conditions.

I&M conducted a review of the Candidate Portfolios through a scorecard and refined the list of Candidate Portfolios to those that represented what I&M considered to be viable strategic options. Rationale for the eliminated candidate portfolios was provided. Six portfolios were left for further analysis to inform the development of the preferred portfolio. Based on the results of analysis, the Reference' Candidate Portfolio was selected as the basis for the development of the Preferred Portfolio. Using informed professional judgement, the final Preferred Portfolio resulted from modifications by I&M to the optimized Reference' portfolio to better manage near-term capital requirements, project execution, reserve margin and energy position surplus. The following table provides a brief overview of the metrics used to evaluate the candidate portfolios with a scorecard.

Table 21. IRP Objectives and Metrics

Objective Category	Objective	Metric
Affordability	Affordability	20-Year NPV Cost to Serve Load 10-Year NPV Cost to Serve Load
	Rate Stability	95th percentile value of NPV Cost to Serve Load Difference Between Mean and 95th Percentile 5 Year Net Rate Increase CAGR (2025-2029) Capital Investment Through 2028
	Market Risk Minimization	20-Year Average of Purchases as a % of Load 20-Year Average of Sales as a % of Load
Sustainability	Sustainability	% Reduction of CO_2 (2005-2041)
Reliability and Resource Diversification	Reliability	Surplus Reserve Margin above FPR Requirement
	Resource Diversity	Number of Unique Generators (2041) Number of Unique Fuel Types (2041)

(p. 138 of I&M IRP Report)

DIRECTOR'S COMMENTS – I&M's Scenario/Risk Analysis

In this IRP, I&M did not examine how the focused six portfolios would perform under scenarios they were not derived from. Usually, this type of analysis is part of the risk assessment to check the robustness of a portfolio under various futures. It might be helpful to have this analysis conducted before developing the Preferred Portfolio.

As was noted earlier, the three optimized scenarios all use the base load forecast. It appears that all 14 portfolios are based on the base load forecast. No optimized scenario appears to have been based on a high or low load forecast. The Director recognizes that the impact of higher load, for example, will play out over time with relatively small impact on resource choices over the next few years. Nevertheless, it would have been informative to understand how sensitive the level of resources to be acquired over the planning period is with different load forecast assumptions.

According to the discussion in the section titled "Supply-Side Resource Options and Costs" *(I&M IRP p. 94, third paragraph)*, the IRP modeling did not consider ownership structure, but the availability dates for different resources, which seems to be driven by the time it takes to self-build rather than considering the option to execute a PPA or buy an existing facility. This is seen in several places, such as solar *(I&M IRP pg. 101)* and wind *(I&M IRP pg. 102)* not being available until 2025. It is also used as justification for excluding some portfolios, such as the Rockport 2026 *(I&M IRP pg. 140)*. It should be noted that the availability dates potentially had an impact on the model selections, since the maximum amount of wind and solar were always selected in the first year available.

All optimized portfolios have at least 25% of off-system sales as a percent of load. This points to a disconnect between the regional capacity expansion, which determines the wholesale market, and the I&M capacity expansion runs, which take the regional market as a given. There is some level of overbuilding in the I&M runs to sell into the market. Thus, there is an economic interest in additional capacity outside of I&M that was not captured in the regional capacity expansion. In developing the Preferred Portfolio (which was not an optimized case), I&M chose to postpone the addition of some generation. This reduces off-system sales to slightly less than 20%.

The Director appreciates the attempt to measure resource diversity as one of the scorecard metrics. It is doubtful there is a perfect measure of resource diversity, so it is important to keep the limits of any given metric in mind. The "Number of Unique Generators" and the "Number of Unique Fuel Types" metrics can be misleading if there is a substantial difference in the size of generators or if one fuel type provides a disproportionate amount of the total. For instance, a system with one huge generator and several tiny generators would score well on the metric but provide almost no resource diversity.

The Director is of the opinion that we are in a planning environment where it is probably impossible to fully appreciate the extent of uncertainty, much less evaluate and thoroughly understand the implications. To some degree this uncertainty might be of less concern where resources can be brought online more quickly and in smaller increments than was the case years ago. Nevertheless, it is important to focus attention on those near-term resource choices that are similar across different portfolios being evaluated with an eye on those choices that have a least regrets perception.

Given this perspective, the Director believes that I&M provided a good narrative on how they viewed the information provided by the IRP analysis and how this information was used to inform the next step in the development of the resource plan. Such a narrative allows one to better understand where and why I&M exercised judgement in the planning process. The exercise of judgement is critical in an environment characterized by extensive uncertainty.

VI. I&M Future Improvements to Planning Methodology

The Director wishes to recognize some areas being considered by I&M (and AEP more broadly) to improve the long-term resource planning process over the next several years.

1. I&M recognizes that rate design will become an increasingly important element of future utility regulation and resource planning as the industry changes, particularly how and when electricity is used and produced. I&M cites increasing levels of DERs, EVs, and overall electrification that will have a significant and uncertain impact. AMI technology will provide useful and necessary information to better evaluate and disaggregate loads and support future rate design changes. *(See I&M IRP, p. 74)*
2. I&M thinks that continuing to provide safe, reliable, and affordable energy in the future will require an integrated approach between transmission, distribution, and resource planning. A fully integrated planning process will require new tools, models, processes, and capabilities. To address this need, AEP has engaged a consultant to produce a roadmap for AEP and I&M to achieve a fully integrated planning process. *(See I&M IRP, p. 88)*
3. I&M expects deployment of AMI meters across all I&M's service territory will be complete by 2024. I&M expects AMI data will improve the company's understanding of customer usage patterns, especially regarding emerging technologies such as EVs and DERs, and be a

key input to the load forecast. I&M expects to be able to use AMI data to inform the load forecast for I&M's next IRP. *(See I&M IRP, p. 56)*

DIRECTOR'S COMMENTS – I&M's Potential Planning Improvements

The Director appreciates the emphasis on developing the tools and data to better understand how and when customers consume electricity. EVs and DERs, for example, have the potential to impact not only the amount of energy consumed but will also likely cause changes in the load shape across the day and year. These changes will affect the economics of resource choices.

The Director agrees with I&M that rate design will be an increasingly important tool for a utility to use. This recognizes that both the magnitude and shape of load is to some degree controllable through rate design. Rate design induced changes to load can affect resource choices. Thus, rates need to be seen as a component of sound resource planning.

Lastly, the Director agrees that economics, technology, and the provision of good utility service increasingly require an integrated approach between transmission, distribution, and resource planning. The Director expects that the next IRP Contemporary Issues Technical Conference will focus on this issue.

VII. Stakeholder Comments

(Director's responsive comments are indented and in italics)

The following comments are intended to be a representative sampling of the public input into I&M's 2021 Integrated Resource Planning. There were similar comments raised by more than one commenter. To reduce redundancy, the Director selected some of the more salient and representative commentary.

Office of Utility Consumer Counselor (OUCC)

The OUCC raised a few concerns about specific projections used in the IRP development.

<u>Commodity Indices</u>

The OUCC is generally concerned that the economic assumptions used by I&M of various commodity prices and their fluctuations need to be updated given significant changes in the economic environment and rising inflation. The OUCC notes that West Texas Intermediate (WTI) crude oil prices fluctuated by approximately $50 per barrel since mid-2021 to approximately $110 per barrel in April 2022. Similar concerns apply to commodity indices for non-ferrous metals wire and cable, steel, transformers, and regulators which increased by 30% since mid-2021.

The OUCC thinks the changes in WTI and other commodity prices coupled with broader inflation could cause changes in the composition of the preferred portfolio.

<u>Environmental</u>

The OUCC expressed concern about the impact on Rockport Units 1 and 2 of potential changes to a few environmental regulations. The environmental regulations specifically referenced were the Steam-Electric Generation Effluent Limitations Guidelines (ELG), the Coal Combustion Residuals

(CCR) Rule, and a proposed plan for 25 states, including Indiana, to achieve each state's Clean Air Act "good neighbor" obligations for the 2015 Ozone National Ambient Air Quality Standards.

The OUCC is concerned Rockport Units 1 and 2 could be forced to retire earlier than the Preferred Portfolio's assumed 2028 for Rockport Unit 1 and Unit 2's assumption to provide capacity until 2024.

While I&M provided detailed descriptions and updates of various environmental regulations affecting generation facilities, the OUCC states that I&M did not provide a description of the technological requirements and costs assumed for each generating unit to comply with each regulation. The OUCC recommends I&M provide more detailed compliance costs in future IRP filings.

<u>DSM</u>
I&M hardwired in the resource optimization the energy and demand savings for the conservation voltage reduction program and the DR program. The OUCC is concerned that I&M did not allow these programs to compete on a level playing field with supply-side resources.

> *Director Response: All technology requirements and costs used in the IRP development should be made available to entities that have signed a non-disclosure agreement. The behavior of commodity markets over the last several months and the extent of ongoing uncertainty, especially in fossil fuels, highlights the need to consider a broad range for critical drivers in the resource planning process. Fortunately, integrated resource planning is an ongoing activity that provides opportunities to incorporate new information as circumstances are continuously changing.*

Indiana Advanced Energy Economy (AEE)

AEE had three main considerations:
1. I&M should further develop EE and DR programs.
2. I&M's procurement of new gas peaking and baseload resources in 2028, 2034, and 2037 adds unnecessary risk for customers.
3. I&M should expeditiously move to more integrated planning to prepare for growth in DERs and Evs.

<u>EE and DR Programs</u>
I&M's investment in AMI creates an opportunity to capitalize on the functionality of AMI, including collection and use of granular customer meter data, to create innovative programs that help shape load, reduce peak demand, improve integration of DERs, and enhance opportunities for higher levels of EE achievement.

AEE notes that on average in 2018, utilities only achieved savings of 1.03% of retail sales from utility-sponsored EE programs. I&M is well below average, indicating a great potential for increased EE program savings. AEE thinks this may indicate that I&M's methodology for evaluating and selecting EE resources is especially conservative. AEE argues the commission should closely scrutinize I&M's approach to EE analysis and encourage changes ahead of the next IRP.

AEE says that programs aimed at peak shaving or shifting demand to off-peak hours, including time-of-use rates, have proven to be a low-cost strategy to save ratepayers money. One effective strategy to unlock these benefits from residential customers is to engage households at scale. For example, with the installation of AMI, and using an opt-out program design, behavioral demand response can turn every household into grid assets through behavioral nudges alone. Layering price signals on top of behavioral nudges would drive larger peak load reductions and load shifting. I&M AMI deployment means these tools can be used in Indiana.

New Gas Resources

AEE recognizes the energy transition introduces new uncertainties, and that I&M intends this IRP to remain flexible and responsive to changing circumstances. However, AEE cautions I&M against the inclusion of significant new natural gas resources in either the near- or long-term. This includes 1,000 MW of peaking capacity in 2028, 500 MW in 2034, and 250 MW in 2037, along with 1,070 MW of CC capacity in 2037. The potential acquisition of these gas resources creates significant customer risk through exposure to volatile natural gas prices for decades.

I&M leaves open the option to convert these plants to hydrogen, but the economics of fuel conversion of a CT, and the availability and cost of clean hydrogen gas supply, are speculative currently. This creates a heightened risk of stranded assets if hydrogen technology does not materialize or is too expensive.

AEE believes another risk is related to the PJM capacity value of I&M's thermal generators. A recent AEE report questions the capacity value of conventional thermal generation, including natural gas, due to four categories of uncertainty and risk that the Equivalent Forced Outage Rate Demand (EFORd) methodology fails to capture. These include outage variability obscured by the use of annual averages, correlated outage risks, weather-dependent stress on equipment, and fuel availability. The risk of reduced capacity accreditation for gas-fired capacity should be thoroughly evaluated in I&M's IRP portfolio scorecard and narrative.

Energy Storage

The preferred portfolio includes a very modest investment in storage in combination with solar beginning in 2027 with cumulative deployment of 60 MW by 2041. AEE believes I&M's traditional modeling of energy storage undervalues the resource.

According to AEE, storage thrives on price variability that provides frequent opportunities to buy low and sell high. High peak vs. valley price spreads also increases net revenue. Many IRP models, including the one used by I&M, fail to recognize the full value of storage for at least three reasons:

- They generally under-represent both the frequency and size of hourly price variation
- They ignore intra-hour price variation
- They typically use reserve margins instead of modelling all ancillary service values, which ignores the agility of storage, in that can provide responses to grid conditions without scheduling reserve generation.

AEE presented graphs to illustrate the way in which inter-hour price variation is commonly underrepresented in traditional IRP models, including the one used by I&M. Further, there is significant variation in prices within each hour in actual power markets that is ignored in an IRP model that calculates with only an hourly granularity. AEE also argues that IRP models fall short of describing all the operational limitations of real power plants.

Because of the limitations in how energy storage was modeled in the I&M IRP, AEE considers it a virtual certainty that storage has been under-valued and under-selected in I&M's 2021 IRP in favor of gas peaking capacity. AEE therefore recommends that I&M's near-term resource procurements be structured so that storage and storage hybrid resources can respond and be properly valued.

AEE recommends that I&M in the next IRP adopt best practices used in other jurisdictions to better capture the value of storage.

<u>Integrated Planning to Prepare for Growth in DERs and Evs</u>
According to AEE, the distribution grid is the backbone of a reliable electricity system and plays a critical role in integrating distributed technologies, including Evs. Utility distribution planning will need to be more nimble, transparent, and fully integrated with other planning processes. AEE recognizes these changes take time but encourages I&M to move expeditiously.
AEE also thinks I&M should be encouraged to implement non-wires alternatives (NWA) to meet distribution system needs when NWA provide greater net benefits than wire-related solutions. Use of competitive procurements to acquire NWAs should be used when appropriate.

> *Director Response: While the Preferred Portfolio includes 1,000 MW of CT resources in 2028, I&M commits to conducting future competitive procurement processes to determine the optimal resource selections based on market conditions at that time.* (See I&M IRP Report, p. 146) *The Director expects that the modeling and analysis of energy storage will also be improved, especially intra-hour analysis to better account for ancillary service benefits that are not normally captured with hourly dispatch models.*
>
> *The Director has already commented on and supports I&M's intention to begin a transition to a more expansive form of planning to bring together distribution, transmission, and more traditional resource planning into a more integrated whole. An important element needs to be a broader analysis of the potential for Evs and DERs (including EE) to affect load, both the magnitude and shape, to better understand potential changes needed at the distribution level and the implication for the bulk power system over time.*
>
> *The Director also supports the evaluation of various rate structures and other programs that focus on the capability to influence the timing and level of energy consumption. Of course, it is especially important, and complicated, to evaluate how DERs, Evs, rate design, and utility-scale generation resources interact with each other. Increasingly, utility resource choices must account for these interactions among technologies across all stages of the provision of electric service to retail customers.*

Reliable Energy

Reliable Energy sees three primary flaws in the IRP process:

a. The IRP process is out of control. The commission does not participate in the development of the IRP. The final Director's Report is often issued after the utility has filed for a Certificate of Public Convenience and Necessity (CPCN) based on the IRP. The lack of IRP hearings before the commission limits commission engagement and the fairness of the process. Neither the utility nor the commission considers how an individual utility IRP is affected by the collective activity of other utilities in the state or the relevant RTO.
b. The IRP development process fails to consider the rapidly changing energy market or balance the interests of the utility to maximize profits in modeling its resource decisions.

The IRP metrics used by I&M do not provide an accurate assessment of the costs of resource decisions, nor does the model adequately address reliability, resiliency, and market risk.

c. I&M/AEP admits that its plan may not even be possible without significant developments in technology and changes in environmental laws that will make the plans truly realistic and economic. Overall, the IRP process has become too mechanical and less strategic as the utilities spend enormous resources in modeling and stakeholder involvement, and less in considering ratepayer impacts, how best to ensure system reliability, and how other utilities in Indiana and nearby states could be relevant to their resource choices.

Process and Evidentiary Issues

The informal stakeholder process allows utilities to control the flow of information, impose their own biases on the preferred outcome, and results in the elimination of otherwise reasonable and economic portfolio alternatives.

There is limited consistency across utilities over which metrics are used and how those metrics are determined. Reliable Energy believes the Commission should set minimum required metrics that all utilities must provide. The required metrics should include:

- A ratepayer impact analysis by customer class over the first 10 years of the proposed resource's economic life.
- NPV of revenue requirements, including sunk and base rate costs by year with summarized values for 10 and 20 years to get a more accurate sense of customer costs.
- Life cycle analysis of carbon emissions, including upstream emissions.
- Capacity and energy diversification by source and type by year to assess reliability and resilience.
- Percent of energy and capacity forecast to be purchased under PPAs in each year to determine market risk and potential price volatility.
- Stranded capital costs due to resource retirements that will later be sought for ate recovery by year under each scenario.
- Costs in base rates associated with each proposed resource retirement.

Other parameters should be standardized across IRPs as well, including:

- New investments in all fossil generation should be fully depreciated by 2035 unless equipped with carbon capture.
- Sensitivity analysis should be the primary analytical tool (as opposed to stochastic analyses) to evaluate assumptions regarding commodity prices, capacity and energy prices, resource capital costs, and load growth. Stochastic results do not inform the Commission about the range of potential impacts. Sensitivity analysis is used to help determine a model's overall uncertainty, an analysis at the core of determining the reliability of a utility's preferred portfolio.

By the time a CPCN case is filed, the utility has already taken significant action to implement its own "Preferred Portfolio" by issuing RFPs, announcing the shutdown of existing plants, and entering into contractual arrangements with project developers. Indiana utilities game the process by dividing requests into multiple CPCN filings so the entirety of the requests are not considered as a whole.

Also problematic is the failure to have a "plan B" if a proposed project is rejected.

The Commission should formalize its involvement in the IRP development process. A formal IRP proceeding would include:

- The IRP and its supporting documentation becoming part of the evidentiary record.
- The utility and stakeholders would have the opportunity to provide sworn testimony during public hearings.
- The Presiding Officers would be available to resolve discovery disputes.
- Parties would receive official notice of new developments in the proceeding rather than relying on periodic checks of the Commission's IRP website for updates.

The outcome of a formal IRP process could include the Commission:

- Providing guidance as the IRP development process unfolds, including actions to avoid errors, balance interests, and encourage reasonable outcomes.
- Balancing requests for changes to the IRP modeling.
- Providing specific comments on the methodologies, assumptions, programs, etc.
- Defining how customer affordability is measured.
- Addressing issues of reliability and resilience.
- Clarifying questions or seeking additional information regarding the IRP.
- Supporting the parties in working together towards solutions or alternative approaches to IRP development.

Reliable Energy has confidence that a far more balanced result would occur from the formal IRP proceedings before the Commission.

Reliable Energy goes on to conclude that I&M's resource plan is hypothetical because I&M recognizes that sources of power in the future are not fully developed and cost-effective. That future generation technologies depend on research and development. Reliable Energy then goes on to say that given this circumstance, I&M's IRP should not be considered a road map for I&M's future.

According to Reliable Energy, now is the time for the Commission to correct the antiquated and imbalanced IRP process that has existed for 40 years.

Reliable Energy included an attachment that was submitted in response to I&M's March 9, 2021 IRP Stakeholder Meeting and slide deck. The attachment covered several topics including metrics used to evaluate resource portfolios, fuel price forecasts, carbon policy assumptions, and others.

<u>Natural Gas Supply and Pricing Concerns</u>
Reliable Energy does not think the overview/price forecast by I&M adequately addresses concerns and costs related to:

- Future ability related to pipeline construction.
- Lack of natural gas storage growth.
- Physical and cyber risks to pipeline delivery of gas.
- Cost of firm and interruptible gas transportation.
- Potential linkage between LNG and domestic natural gas pricing.
- Methane controls at the wellhead.

Renewable Integration
A large concern of IRPs should be the cost and constraints related to renewable integration.

All Source RFP
The all-source RFPs conducted by Indiana utilities have proven to be problematic and not good indicators of future costs. The lessons from the recent experiences of both NIPSCO and Vectren are that IRP assumptions regarding renewable pricing may not be achievable and that even an all-source RFP is not dispositive. I&M should explain how it plans to address the inherent uncertainty of the all-source RFP process.

Director Response: The Director appreciates Reliable Energy's well-intentioned thoughts on how to improve the IRP stakeholder process and, more generally, the development of the IRP methodology and content. Reliable Energy does an excellent job highlighting the difficulty of making utility-specific resource choices in a complex and rapidly changing environment. However, almost all these difficulties were explicitly addressed in the IRP itself or the stakeholder meetings. Long-term resource planning is continually improving. Much of Reliable Energy's comments question the effectiveness of the IRP stakeholder process, the usefulness of the Director's review of the IRP and process, and the usefulness of any commission review in a subsequent regulatory proceeding. The Director's response is that the process has seen a massive improvement in the IRP quality and stakeholder input. It is undeniable that there is room for improvement. It is also open to debate how much of these changes would have occurred anyway. Surely the process developed by the Commission has facilitated much of these improvements.

Methodological Considerations
It is important for a utility to discuss how it evaluated the impact of specific resources, and potential future resource portfolios, on its ability to provide reliable and economic service while operating within an RTO region experiencing similar resource portfolio changes. To the Director's knowledge, this is work at the forefront of integrated resource planning. Consideration of how a utility makes resource choices within a broader region experiencing significant portfolio changes begins with a clear statement of the problem and the corresponding questions that need to be asked to reasonably structure the analysis. As is the case for any risk and uncertainty analysis, there is not likely to be a clear answer that satisfies all criteria. Rather, the key will be to develop the questions to be addressed, explore how these questions can be evaluated, and to provide a well-developed discussion of how the company used and interpreted the information developed in the planning process.

The behavior of commodities markets over the last several months and the extent of ongoing uncertainty, especially in fossil fuels, highlights the need to consider a broad range of critical drivers in the resource planning process. Fortunately, integrated resource planning is an ongoing activity that provides opportunities to incorporate new information as circumstances are continuously changing.

The Director disagrees with the preference Reliable Energy expresses for sensitivity analysis compared to stochastic analysis. Scenario analysis, sensitivity analysis, and stochastic (probabilistic) analysis are all useful tools for evaluating different risks in a world where the future is unknowable. Decisions to acquire resources cannot be avoided and the information provided by these forms of analysis (if used well) provides a better foundation for making these decisions.

The Director appreciates the numerous helpful suggestions provided by Reliable Energy to improve the IRP itself, both methodology and evaluation metrics. The Director would find it helpful if Reliable Energy would cite specific examples of these recommended improvements being used by other utilities and states across the country.

Citizens Action Coalition, Earthjustice, and Vote Solar (Joint Commenters)

The Joint Commenters provided detailed comments on numerous aspects of I&M's IRP, not all of which will be addressed by the Director. This is largely due to a number of the areas discussed by the Joint Commenters having already been addressed in other sections of this report.

<u>Access to IRP Model Inputs and Outputs</u>
Emphasis was placed on the need to provide better and more timely access to IRP model inputs and outputs. The Joint Commenters recommended that I&M consider using a process of releasing and sharing information like the process used by AES Indiana for its 2019 IRP and is currently using for its 2022 IRP. AES Indiana is using a file sharing site to share information at several points in time throughout the IRP development process using a set schedule. Information is only shared with those stakeholders with an executed nondisclosure agreement (NDA) with AES Indiana. The Joint Commenters believe this facilitates stakeholder involvement throughout the process.

<u>New Resource Build Constraints</u>
Joint Commenters recognized that annual and cumulative build constraints were applied by I&M in AURORA for new solar and wind resources. I&M said these constraints were informed by responses to the Company's RFP. According to I&M, these constraints were necessary to keep the optimization model from selecting an unlimited number of solar resources.

The Joint Commenters acknowledged that some constraints are necessary and that the limits used in this IRP are an improvement over those used in the previous IRP. However, the Joint Commenters are skeptical of the need to model Tier 1 and Tier 2 solar tranches separately. Tier 1 solar represents the "Best-in-Class solar resource and is based on the lowest bid received for solar resources from the All Source and Renewable RFP," while Tier 2 is "the average of higher bids received as part of the All Source and Renewable RFP."

Joint Commenters argue an all-source RFP process that is well run will likely result in price separation between bids, but it is unlikely that I&M would only receive 250 MW of bids for best-in-class solar projects and 250 MW for the next best. Also, the RFP results are likely to change if I&M conducts RFPs periodically throughout the study period.

The Joint Commenters provided a table showing the capacity expansion plan for the Reference candidate portfolio, which is the optimized portfolio used to develop the Preferred Plan. The table shows that the annual constraint for solar was met each year for the period 2025 – 2027, and the annual and cumulative constraint for wind was binding in 2025 and 2026.

I&M did evaluate some scenarios that allow for a bigger buildout of new renewable resources. The Joint Commenters state that as the limits on renewable resource additions are relaxed under both the Expanded Build Limits and the Reference with No Renewable Limits Scenarios, the resource acquisitions shift away from new gas and towards more solar, wind, and battery storage resources.

Energy Efficiency

The Joint Commenters noted that I&M and GDS Associates sought input from members of the I&M DSM Oversight board in the development of the MPS through four meetings. Citizens Action Coalition (CAC) found the development process generally open and collaborative. GDS was responsive to comments and included many of the recommendations made by CAC.

The Joint Commenters discussed an inconsistency between the MPS and IRP in that the MPS did not consider the avoided cost of carbon regulation. The IRP Reference Scenario included the assumption that carbon regulations would start in 2028. The Joint Commenters argue that had the MPS included a similar carbon regulation assumption that more measures would have been cost-effective. That this inconsistency meant a smaller amount of EE was made available for selection within the IRP.

The Joint Commenters discuss that the IRP modeling used the MPS Program Potential scenario while excluding the RAP and MAP savings. They believe this places limits on future EE potential based on existing program design, budget, and incentive levels. That dozens of measures were excluded from the IRP modeling despite being economically attractive.

According to the Joint Commenters, the MPS RAP scenario only included 22 emerging technology measures (8 residential and 14 C&I). In the residential sector, emerging technology measures accounted for only 3-5% of incremental annual savings in the RAP scenario. In the C&I sector, emerging technology measures accounted for only 1-3% of incremental annual savings in the RAP scenario.

The Joint Commenters argue the nature of new technology is 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 later years of the analysis when the measure might be cost-effective. In the Joint Commenters' opinion, failure to account for these technologies results in conservative and unrealistic view of potential savings.

The Joint Commenters reference a study done for Consumers Energy evaluating emerging technologies. According to the Joint Commenters, the Consumers Energy study found in years three through nine, emerging technologies account for roughly 20% of achievable potential. While in later years, the study found emerging technologies account for approximately two-thirds of the achievable potential. They conclude these results demonstrate the importance of adequately accounting for emerging technologies in a market potential study.

I&M does not model the costs of DSM resources on a levelized cost basis. Instead, EE program costs are only incurred during the year of measure installation. The Joint Commenters disagree with this approach because it creates an end-effects problem in which the full costs of DSM are accounted for, but savings are truncated or under counted.

The Joint Commenters also have concerns with the approach used by I&M to form EE bundles modeled in the IRP. I&M used a k-means clustering approach to bundle measures. An approach that means I&M cannot say that the selected measures would actually conform with a coherent program design. The Joint Commenters recommend I&M consider a different approach to bundling and express a desire to collaborate with I&M on a bundling approach.

Lastly, the Joint Commenters not there is a lack of clarity as to how the IRP processes captured the effects of both existing and new DR resources.

<u>I&M's Preferred Portfolio</u>
The Joint Commenters note that I&M's Preferred Portfolio is not a pure optimized plan. Rather, the Preferred Portfolio is based on the expansion plan from the Reference Candidate Portfolio but with some wind, solar, and CT resource additions moved around. I&M explained the modifications as actions to reduce risks around near-term capital requirements, project execution, reserve margin and energy position surplus influence on portfolio costs and to improve alignment with overall objectives and metrics.

The Joint Commenters believe these changes are not just adjustments by a year or small changes in capacity but are radical departures. The Joint Commenters say it can be reasonable to make out-of-model changes to an optimized portfolio, but the changes reflected in the Short-Term Action Plan radically change the near-term resource mix. They note the Preferred Plan pushes 1,300 MW of wind and solar selected by the model in 2025 and 2026 out to later in the planning period and slides forward additional gas capacity by five years.

The Joint Commenters recognize that all portfolios passed to the scorecard stage were long on energy and many were long on capacity. They argue if I&M was concerned about this that it should have used the optimization modeling to test additional portfolios including earlier retirement of units to evaluate the nature of a portfolio with less sales. That I&M could also have set limits on export sales in its modeling to understand how these limits might affect the optimization selection of resources.

> *Director's Response: The Director appreciates the detailed review by Joint Petitioners of EE in the I&M IRP. It is the Director's perspective that the importance of projecting the impact of EE resources over the full 20-year planning horizon is less significant than it once was.*
>
> *Generation facilities today can be brought online in three to five years compared to the 8 – 10 years for more traditional generation facilities. The average size of utility scale generation additions is also much smaller today. Generation additions are 300 MW or less, and often in the 100 MW – 150 MW range. This compares to 500 MW to 800+ MW for coal-fired facilities. Shorter periods to commercial operations for new units and smaller capacity increments lessens the importance of projections of EE for the full 20-year planning horizon.*
>
> *Given this circumstance, it is critical that the EE potential over the next 5 – 8 years be thoroughly evaluated in both the MPS and the IRP optimization process. Also, it is important to capture in both the MPS and the IRP the interactions between EE resources and other forms of DERs. EE potential is reassessed in every iteration of the IRP cycle.*
>
> *Also, the Director thinks EE should be evaluated to better understand how it can lessen or otherwise modify utility and customer exposure to the potential implications of uncertainty and the resulting risks. The Director thinks this is an area that is generally overlooked and underappreciated.*