



Draft Director's Report
for Indiana Michigan Power Company's 2018-2019
Integrated Resource Plan
July 17, 2020

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Draft Director's Report Applicable to Indiana Michigan Power Company's 2018-2019 Integrated Resource Plan and Planning Process

I. PURPOSE OF IRPS

Indiana Michigan Power Company's (I&M) 2018- 2019 IRP was submitted on July 1, 2019. By statute¹ and rule,² integrated resource planning requires each utility that owns generating facilities to prepare an integrated resource plan (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 IRP 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.³

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 IRP, 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.⁴ By identifying uncertainties and their associated risks, utilities will be better

¹ Indiana Code § 8-1-8.5-3.

² 170 IAC 4-7; see also "Draft Proposed Rule from IURC RM #11-07 dated 10/04/12", located at: <http://www.in.gov/iurc/2843.htm> ("Draft Proposed Rule")

³ 170 IAC 4-7-2.2(g)(3).

⁴ In addition to forecasting changes in customer use of electricity (load forecasting), IRPs must address uncertainties pertaining to the fuel markets, the future cost of resources and technological improvements in resources, changes in public policy, and the increasing ability to transmit energy over vast distances to access economical and reliable resources due to the operations of the Midcontinent Independent System Operator (MISO) and PJM Interconnection, LLC (PJM).

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 factors⁵ 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 following statement of purpose is consistent with the integrated resource plan (IRP) statute and rule.

This 2018-19 Integrated Resource Plan (IRP, Plan, or Report) is submitted by Indiana Michigan Power Company (I&M or Company) based upon the best information available at the time of preparation. This Plan is not a commitment to specific resource additions or other courses of action, as the future is highly uncertain. The Plan strives to maintain optionality in meeting I&M's resource obligations to take advantage of market opportunities and technological advancements. Accordingly, this IRP and the action items described herein represent an indicative plan and are subject to change as new information becomes available or as circumstances warrant. *(I&M IRP page ES-1)*

The utility's Executive Summary in its IRP submittal continues to say:

An IRP explains how a utility company plans to meet the projected capacity (i.e., peak demand) and energy requirements of its customers. I&M is required to provide an

⁵ A primary driver of the change in resource mix is due to relatively low cost natural gas and long-term projections for the cost of natural gas to be lower than coal due to fracking and improved technologies. As a result, coal-fired generating units are not as fully dispatched (or run as often) by MISO or PJM. The aging of Indiana's coal fleet, the dramatic decline in the cost of renewable resources, the increasing cost-effectiveness of energy efficiency as a resource, and environmental policies over the last several decades that reduced emissions from coal-fired plants are also drivers of change.

IRP that encompasses a 20-year forecast planning period (in this filing, 2019-2038). This IRP uses the Company's current long-term assumptions for:

- Customer load requirements – peak demand and hourly energy;
- commodity prices – coal, natural gas, on-peak and off-peak power prices, capacity and emission prices;
- existing supply-side resource retirement options;
- supply-side alternative costs and performance characteristics – including fossil fuel, renewable generation, and storage resources;
- transmission planning and
- demand-side management program costs and impacts.

In addition, I&M considered the effect of environmental rules and guidelines, which have the potential to add significant costs and present significant challenges to operations. This IRP also considers the potential cost associated with some form of future regulation of carbon emissions, during the planning period, even though there is considerable uncertainty as to the timing and form future carbon regulation may take. This IRP also evaluates a 'No Carbon' scenario that assumes a future without carbon regulation. To meet its customers' future capacity and energy requirements, I&M assumes the continued operation of its existing fleet of generation resources for a portion of the 20-year plan, including the two base-load coal units at the Rockport Plant, and the two units at the DC Cook Nuclear Plant (Cook). A key assumption in several scenarios is that the Rockport Unit 2 lease expires in late 2022 and Rockport Unit 1 retires at the end of 2028. Other Rockport unit retirement scenarios are also evaluated in this IRP and described in Section 5. Importantly, all of the Rockport IRP assumptions that underpin this IRP are intended for use in this IRP only, as several key decision variables, including the Consent Decree modification and final Unit 2 lease disposition, remain open. Another important assumption in this IRP is that Cook units will operate through the remainder of their current license periods, although the Company may explore future life-extension opportunities. The Company also assumes the continued operation of its run of river hydroelectric and solar plants.

The Company has a portfolio of 450MW of purchase power agreements consisting of four wind farms. During the planning period, these contracts will expire. In addition, the Company is planning to install 64MW of solar resources by 2023, which for this IRP are assumed to be "going-in" or "existing" resources. Another consideration in this IRP is the increased adoption of distributed rooftop solar resources by I&M's customers. While I&M does not have control over where, and to what extent, such resources are deployed, it recognizes that distributed rooftop solar will reduce I&M's growth in capacity and energy requirements to some degree. Importantly, I&M operates within the PJM Interconnection, L.L.C. (PJM) Regional Transmission Organization (RTO), while most Indiana and Michigan utilities operate in the Midcontinent Independent System Operator, Inc. (MISO) RTO. As expected, each RTO has its own capacity planning process that results in different resource planning criteria and assumptions.

In this IRP, the Company continues to model portfolios that not only add resources to meet its PJM capacity obligation, but also provide zero variable cost energy to enhance rate stability, reduce emissions and further diversify its generation portfolio. *(I&M IRP pages ES-1 and ES-2)*

For this IRP, the key assumption in several scenarios is the status of the Rockport Unit 2 lease, which expires in late 2022, and Rockport Unit 1, which could retire at the end of 2028. Other Rockport unit retirement scenarios are also evaluated in this IRP and described in Section 5. Importantly, all of the Rockport IRP assumptions that underpin this IRP are intended for use in this IRP only, as several key decision variables, including the Consent Decree modification and final Unit 2 lease disposition, remain open. Another important assumption in this IRP is that the Cook units will operate through the remainder of their current license periods, although the Company may explore future life-extension opportunities. *(I&M IRP page ES-2)* I&M analyzed scenarios that would provide adequate resources and minimize costs to I&M's customers over the 20-year planning horizon and selected a *Preferred Plan*.⁶ *I&M IRP page ES-3)*

III. FOUR PRIMARY AREAS OF FOCUS

Consistent with the introductory comment, the primary areas of focus include: load forecasting; demand side management (DSM) which includes energy efficiency (EE) and demand response (DR)); risk / scenario analysis; the stakeholder process, and the need for continual improvement such as modeling all forms of distributed energy resources (DERs) and electric vehicles (EVs).

A. LOAD FORECAST

I&M serves approximately 466,000 retail customers in Indiana and 129,000 retail customers in Michigan. I&M has two 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; the highest recorded winter peak was 3,952 MW, which occurred in January 2015. The most recent (summer 2018 and winter 2018/19) actual I&M summer and winter peak demands were 4,369 MW and 3,770 MW, occurring on June 18, 2018 and Jan. 30, 2019, respectively. *(I&M IRP Public Summary, page 1)*

Over the next 20-year period (2019 to 2038) I&M is projecting a relatively flat residential customer count growth rate of 0.1% per year. Residential retail sales growth is projected to be flat, commercial sales growth is expected to decline by -0.3% per year, and the industrial class is expected to grow about +0.4% per year. The result is that I&M's retail sales grow at a 0.1% rate per year. I&M's internal energy and peak demand are expected to

⁶ The Preferred Plan would: 1) continue the operation of the Cook Units through their current license periods; 2) retain the Rockport Unit 2 until the lease expires at the end of 2022; 3) retire the Rockport Unit 1 at the end of 2028; 4) beginning in 2022, I&M would deploy 3,600 MW of wind and large scale solar by 2038; 5) integrate 50 MW of batteries and 54 MW of microgrid resources by 2028; incorporate 180 MW of energy efficiency and demand response; and anticipates residential and commercial customers will install rooftop solar and other distributed generation.

decrease at an average rate of 0.2% per year, respectively, through 2038. (*I&M IRP Public Summary, page 2*) I&M provided the following graphic to illustrate the load forecasts in the different scenarios (I&M IRP, page 31)

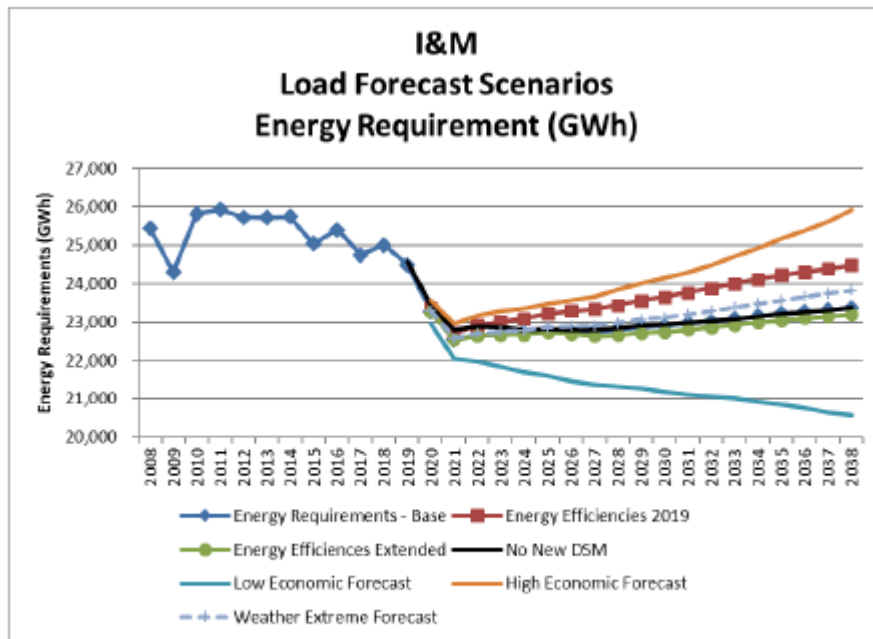
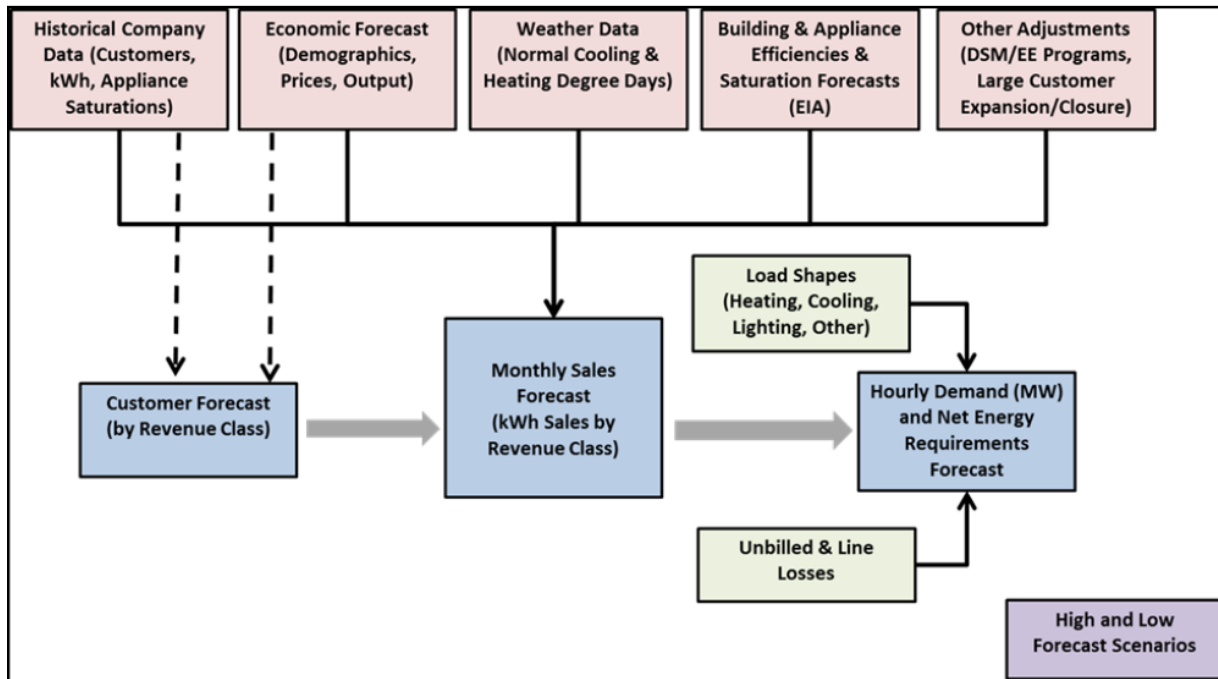


Figure 10. Load Forecast Scenarios

I&M's load forecasts are primarily based on econometrics such as the use of ITRON's Statistically Adjusted End-Use (SAE) model and time series data. A short-term (approx. 24 months) and long-term (approximately 30 years) forecast are prepared. The short-term forecast is an ARIMA (Autoregressive Integrated Moving Average) that considers weather (e.g., heating and cooling degree days) and trends in customer use, and assumes the existing stock of end-uses to be fixed. For industrial customers, factory orders and inventory are included in the ARIMA. I&M believes ARIMA provides more accurate results for short-term forecasts. The long run forecasts attempt to capture structural changes such as changes in end-use, technology, natural gas prices, population/demographics, real personal income, employment, gross regional product, economics, etc. In the long-term, customers can change their appliance/end-uses in response to electric price changes and other factors. Figure 2 (below) is useful. (*I&M IRP, page 10*) The short and long-term models are blended, largely based on professional judgment, to smooth the transition. (*I&M IRP, pages 9-12*) The blending process combines the results of the short-term and long-term models by assigning weights to each result and systematically changing the weights so that by July 2021 the entire forecast is from the long-term models. (*I&M IRP, page 16*)



I&M's load forecast was developed by AEP's Economic Forecasting organization and completed in June 2019. Underlying forecasts include an economic forecast by Moody's Analytics to develop the customer forecast, the sales forecast, the peak load, and internal energy requirements forecast.⁷ (*I&M's IRP, page 7*) I&M's IRP also generally discusses the potential for reduced energy use and demand as a result of EE, DR, batteries, microgrids, rooftop solar, distributed generation, and other DERs.

I&M's load forecasts for industrial customers relies heavily on customer service engineers to obtain information from those customers (*I&M IRP, pages 8 and/or 15*) that may alter the large commercial and industrial load forecasts. I&M also uses as explanatory variables its service territory's Gross Regional Product for manufacturing, employment, electric prices, and Federal Reserve Bank (FRB) industrial production indexes. (*I&M IRP, page 15*)

I&M forecasts public street and highway lighting as a function of economic variables such as service area employment or service area population and binary variables. Wholesale

⁷ The load forecasts for I&M and the other operating companies in the AEP System incorporate a forecast of U.S. and regional economic growth provided by Moody's Analytics. The load forecasts utilized Moody's Analytics economic forecast issued in December 2019. Moody's Analytics projects moderate growth in the U.S. economy during the 2019-2038 forecast period, characterized by a 2.0% annual rise in real Gross Domestic Product (GDP), and moderate inflation, with the implicit GDP price deflator expected to rise by 1.9% per year. Industrial output, as measured by the Federal Reserve Board's (FRB) index of industrial production, is expected to grow at 1.5% per year during the same period. Moody's projects regional employment growth of 0.3% per year during the forecast period and real regional income per capita annual growth of 2.3% for I&M's service area. The Company utilizes an internally developed price forecast that incorporates information from the Energy Information Administration (EIA) outlook for the East North Central Census Region for the longer term. (*I&M's IRP, pages 7 and 8*)

energy sales are modeled as a function of economic variables such as service area gross regional product, industrial production indexes, energy prices, heating and cooling degree-days and binary variables. I&M uses binary variables to account for discrete changes in energy sales that result from events such as the addition or deletion of new customers. *(I&M IRP, page 16)*

I&M integrates weather related assumptions as a variable in its load forecast methodology where appropriate, recognizing some electric use is not highly correlated to weather. *(I&M IRP, page 8)*

The demand forecast model is based on a series of algorithms for allocating the monthly internal energy sales forecast to hourly demands. The inputs into forecasting hourly demand are blended revenue class sales, energy loss multipliers, weather, 24-hour load profiles, and calendar information.

The weather profiles are developed from representative weather stations in the service area. Twelve monthly profiles of average daily temperature that best represent the cooling and heating degree-days of the specific geography are taken from the last 30 years of historical values. The consistency of these profiles ensures the appropriate diversity of the company loads. *(I&M IRP, page 17)*

The 24-hour load profiles are developed from historical hourly Company or jurisdictional load and end-use or revenue class hourly load profiles. The load profiles were developed from segregating, indexing and averaging hourly profiles by season, day types (weekend, midweek and Monday/Friday) and average daily temperature ranges. *(I&M IRP, page 17)*

The profiles are benchmarked to the aggregate energy and seasonal peaks through the adjustments to the hourly load duration curves of the annual 8,760 hourly values. These 8,760 hourly values per year are the forecast load of I&M and the individual companies of AEP that can be aggregated by hour to represent load across the spectrum from end-use or revenue classes to total AEP-East, AEP-West, or total AEP System. Net internal energy 2018-19 Integrated Resource Plan requirements are the sum of these hourly values to a total company energy need basis. Company peak demand is the maximum of the hourly values from a stated period (month, season or year). *(I&M IRP, pages 17-18)*

According to I&M, its end-use load forecasting models account for changing trends and saturations of energy efficiency technologies throughout the forecast period. Given that I&M is also administering EE and DR programs to accelerate the adoption of EE technologies, the load forecast needs to be adjusted to account for the impact of these EE and DR programs not already embedded in the load forecast. As a result, I&M applies a “degradation factor” to adjust EE selected in the IRP model to avoid double counting EE savings; once in the load forecast and also in the IRP optimization selecting EE bundles. This will be discussed more in the discussion of Demand-Side Management. *(I&M IRP, page 24)*

DIRECTOR'S COMMENTS – LOAD FORECASTING

I&M's forecast methodology was well done, the data sources and tools were appropriate for this IRP, and the forecast was well documented both in the report itself and in the appendices. I&M is commended for its stakeholder involvement throughout the process. Especially in the first two stakeholder sessions, I&M provided very good discussions and engaged the stakeholders in better understanding of changing usage patterns and the impact of embedded appliance efficiencies in the forecast.

I&M said there have been only “a limited number of changes in the methodology” since I&M's 2015 IRP (*I&M IRP, page 27*), but only explicitly mentioned the change involving how the high-low economic growth model is now estimated separately for I&M and each operating company. It would have been helpful for I&M to enumerate any methodological changes. As I&M discussed the changing usage patterns, this is an appropriate predicate for I&M to undertake an evolutionarily significant continuing improvement process to better capture changing usage patterns and demographic changes for all classes of customers. Potential enhancements to I&M's methodology will be discussed in this Report.

I&M's application of the forecast methodology resulted in the construction of a slightly broader range of forecasts than in the previous load forecasts in 2015 load forecast (2015 was 10% below and 11% above the base forecast on page 29 of 2015 IRP compared to this 2018 forecast of 12.4% below and 12% above). Given the limited growth rates, these difference are a bit more significant than the percentages reflect. More discussion of the sensitivities, derived from the Energy Information Administration's (EIA) 2019 Annual Outlook that produced high and low growth scenarios, would have been beneficial. It does appear I&M is being responsive to the Director's suggestion that I&M make greater use of I&M-specific data. Additional details and rationale in the narrative would have been useful.

Questions about how EE affected the load forecast remain. The need to implement a process to avoid the potential double counting of energy efficiency is reasonable. The use of degradation factors to lessen the potential for double counting, even if the factors are estimates, seems appropriate at a conceptual level. However, there are a number of EE-related concerns that will be addressed in the DSM discussion. The Director has some specific comments/questions such as:

- 1) The Director understands that short-term models do not capture structural changes in the economy but may be more useful to financial forecasts in the near-term. The Director remains unconvinced of the need for “blending” a short- and long-term forecast. Does I&M anticipate changes to reduce the need for the two forecasts?;
- 2) In the residential forecast (*I&M IRP, page 14*), I&M describes the “Cooling use variable drivers” but lists Heating Degree Days (HDD). Should this be Cooling Degree Days (CDD) or was HDD used in this model? This occurred in the 2013 and 2015 IRPs as well;

- 3) The National and Regional economic forecasts (*I&M's IRP, page 7*) are ascribed to be from Moody's Analytics December 2019. We assume I&M meant December 2018;
- 4) I&M's IRP did not discuss the potential for EVs to increase I&M's energy use and demand as well as changing the load shapes for I&M. While the number of EVs and charging stations may not be significant now, **it may become increasingly important to the load forecast**. Does I&M anticipate future forecasts and IRPs will provide information on EVs?
- 5) It is not clear how or why binary variables are integrated into the forecast. For example, is the "addition or deletion of new customers" binary. (e.g., I&M's IRP page 16) In past Reports, the Director has mentioned the use of binaries *may* mask important underlying information. Does I&M anticipate a review of the need for binaries? Regardless, it would be helpful to discuss the rationale in future IRPs;
- 6) And, with regard to street lighting in specific and lighting generally, I&M's forecast undoubtedly included estimated effects of higher efficiency lights. However, I&M on page 51 of its IRP said efficient lighting could reduce lighting use by 5% by 2033 but it isn't clear this potential was included in their IRP? In future IRPs, will I&M provide additional information on the future of lighting?

B. ENERGY EFFICIENCY

I&M uses the traditional definition of DSM (EE and DR) to encourage efficient energy consumption and to reduce use, especially during peak periods. This section will primarily discuss EE modeling and integration into I&M's IRP resource optimization process due to its relative importance in I&M's selection of resources. Demand response and other distributed energy resources (DERs such as distributed generation, combined heat and power, roof top solar, battery storage, and other customer-owned resources) will be discussed in the demand response and other DER section. I&M's IRP states:

Programs or tariffs that are designed to reduce consumption primarily at periods of peak consumption are demand response (DR) programs, while around-the-clock measures are typically categorized as energy efficiency (EE) programs. The distinction between DR and EE is important, as the solutions for accomplishing each objective are typically different, but not necessarily mutually exclusive. Included in the load forecast discussed in Section 2.0 of this Report are the demand and energy impacts associated with I&M's DSM programs that have been approved in Indiana and Michigan prior to preparation of this IRP. (*I&M IRP, page 49*)

I&M stated there is potential for additional or "incremental" DSM beyond the levels embedded in the load forecast as well as Volt VAR Optimization (VVO). For 2019, I&M anticipates 290 MW of peak DSM reduction (total company basis). (*I&M IRP, page 49*) I&M

estimates that EE (including codes and standards) may reduce residential load, commercial load, and industrial lighting use by over 5% by 2033. (*I&M IRP, page 51*) I&M estimates it currently has the capability of reducing peak demand by 272 MW, with most of the potential reduction coming from interruptible agreements. Residential customers are capable of reducing I&M's peak demand by 2.9 MW. (*I&M IRP, page 53*)

The 2018-2019 IRP adds new EE resources in 2020 that are incremental to the programs already approved or pending approval. The consultant firm, Applied Energy Group (AEG), which developed the 2016 EE Market Potential Study (MPS) for I&M, also developed the inputs for modeling the potential incremental EE in this IRP. This input was developed based on the identified EE potential of the MPS. The amount of available EE is usually described within three sets: technical potential, economic potential, and achievable potential.

I&M identified the measures from the MPS that had the most potential savings to determine which end-uses were to be targeted and in what amounts. That resulted in a list of 20 measures for each of the residential, commercial and industrial sectors. Information provided by AEG about the measure costs, energy savings, market acceptance ratios and program implementation factors were used to develop bundles of future EE activity for demographics and weather-related impacts.

I&M then evaluated the selected incremental EE bundles (up to 29 unique bundles) and used the Plexos model to choose the combination of resources that reduces the overall portfolio cost, regardless of whether the resource is on the supply – or demand-side. These bundles were available to be chosen beginning in 2020 and each of them had Achievable Potential and High Achievable Potential characteristics. Each EE bundle had a Levelized Cost of Electricity (LCOE) and potential energy savings, which are offered into the model as a stand-alone resource. After the model determines the portfolio of optimized resources, I&M considers the details of each EE bundle (e.g. participant costs, penetration rates, bill savings, cost effectiveness) that was optimized to develop appropriate EE offerings to its customers.

Demand Response (DR) and other DER modeling

As a member of the PJM Interconnection, LLC (PJM), I&M's contribution to PJM's peak demand, coincident with PJM's peak, serves as the criterion for I&M's resource adequacy obligations. I&M's maximum (system peak) demand is likely to occur on summer days that have the highest average daily temperature which is typically during a weekday, mid to late afternoon. (*I&M IRP, page 52*)

I&M has two customers with interruptible load contracts for interruption during the winter and summer peaks. The interruptible load is considered as a resource that can be used when load is peaking. I&M has agreements with 139 customers that allows the interruption of service only in emergencies. Therefore, I&M's load forecast does not reflect any load reductions for these emergency-only DR customers.

Incremental levels of DR for the residential and commercial sector were respectively modeled based on the Bring Your Own Thermostat (BYOT) program and the “EIS” light interface. I&M mentions that a specific amount of DR resource is offered into the model which may select up to four units of both sectors, in any calendar year, beginning with 2020.

I&M states that the amount of other DERs (including customer-owned distributed resources such as roof-top solar, battery storage, combined heat and power – CHP, microgrids) is, currently, very small. I&M, however, recognizes that all forms of DERs will be increasing with the big question being how quickly. DG, in the form of distributed solar resources, was embedded in amounts in the resource portfolio equal to a Compound Annual Growth Rate (CAGR) of 10.3% over the planning period. CHP resources were made available in the IRP resource selection in 15 MW blocks with an overnight installed cost of \$2,300/kW and assuming full host compensation for thermal energy for an effective full load heat rate of 4,800 Btu/kWh.

DIRECTOR’S COMMENTS – ENERGY EFFICIENCY

EE Modeling

I&M’s long-term load forecast includes existing EE and incremental EE (including general trends in appliance efficiency standards). Existing DSM programs, particularly EE, are reasonably well-defined. Incremental EE programs are not as well defined. Future DSM is developed following a dynamic modeling process using generic cost and performance data. For the near term horizon of this IRP, currently approved DSM programs through 2019 are embedded into the load forecast. Then, the IRP model selected the optimal levels of economic EE for the years 2019-2038 based on projected future market conditions.

I&M’s intention is to model additional EE and DR on the same economic basis as supply-side resources. I&M’s PLEXOS model views DSM as non-dispatchable generators. For projecting future EE, I&M developed a company specific Market Potential Study (MPS) using I&M data which is preferable to primary reliance on information from EPRI and EIA that was used in the 2015 IRP.

Unfortunately, the age of I&M’s MPS (2016) made it potentially stale by the time this IRP was completed (e.g., the MPS used the 2016 Residential Appliance Saturation survey while the IRP used the 2019 Residential Appliance Saturation survey). It is normal for there to be some delay between when a MPS is developed and when the IRP analysis completed. For this IRP, I&M encountered reasonable circumstances that warranted a greater than normal delay due to the uncertainties of its coal fleet. Nevertheless, this dated MPS raises questions about the relevance of the MPS for this IRP. I&M, to its credit, retained a contractor to update the MPS. It appears this update may be part of a routine annual update from the EIA that captures the effects of legislatively mandated efficiency codes and

standards⁸ but it is unclear what was updated and how this update affected the IRP results. For example, how different was the load forecast used to develop the MPS from the load forecast in the 2019 IRP?

Since I&M already conducts a Residential Appliance Saturation survey and is deploying advanced metering infrastructure, it should be a relatively small incremental effort to enhance the load research program. Residential, and the creation of commercial surveys, could be enhanced by having experts conduct a comprehensive assessment of appliances/end uses, demographic information, housing and business data. The appliances/end-uses categories enumerated by the data collected by the EIA should be an appropriate foundation for developing a more comprehensive database that would be superior to the data currently available to I&M. The development of enhanced survey instruments is discussed in more detail in the "Future Enhancements" discussion. (Appendix 2, ITRON's SAE model discussion details the information collected by the EIA's *2018 Annual Energy Outlook (AEO)* beginning on page 1888 for residential customers and page 1931 for commercial customers). Collaborating with other similarly situated utilities, particularly those in Indiana, would also increase the quality and credibility of data to support I&M's IRP.

I&M's IRP should have included more information on EE bundle development. For example, were measure costs the most important factor? If yes, how were other factors considered in the development of EE bundles?

The IRP could have also included more information on the development and use of degradation factors. This could have been done in the body of the report or in an appendix. The information provided in the stakeholder presentations was helpful but only up to a point, and does not substitute for a clear discussion in the IRP itself. Even using information from I&M's three-year DSM case (Cause No. 45285), the Director is not clear how EE bundles were developed or how the degradation factors were developed and applied beyond the use of professional judgement by I&M's resident experts. The Director understands that any long-term forecasting exercise is complicated and is as much an art as a science. This is especially the case when trying to account for the real potential of double-counting EE impacts when using the SAE load forecasting methodology. The problem of interaction between the load forecast and future (or incremental utility sponsored) EE must be addressed and there are only so many ways of doing this, none of which is ideal or demonstrably superior (at least at this time with existing computer capabilities, existing databases, and without a better understanding of customers and DERs). The approach

⁸ EIA end-use saturation, efficiency and annual appliance usage (UEC – Unit Energy Consumption) are derived from the National End-Use Model System (NEMS). While NEMS generates detailed end-use data, EIA is primarily concerned with the high-level projection of total energy requirements,, across all end-uses and sectors including transportation. From an electric or natural gas utility forecaster's perspective, it is the underlying end-use and technology level detail that provides insights into how individual residential and commercial customers are using electricity and natural gas, trends in end-use energy consumption, and what these trends imply for future electric and gas usage at the regional level.

selected by I&M is less than intuitive and puts a burden on I&M to be clearer in its presentation of this methodological choice and its application.

A significant driver of the level of EE selected in the modeling process is the projection of avoided costs. The avoided cost projections developed in I&M's IRP are based on regional modeling estimates of PJM's energy and capacity prices over the planning horizon. I&M recognizes transmission and distribution costs can be avoided with DSM but argues it is too location specific for inclusion in the IRP's analysis of DSM resources. As a result, I&M includes zero avoided costs for T&D. But location specific does not mean zero in the judgment of the Director. The question is what level of potential location specific avoided T&D costs should be included in the IRP and appropriately adjusted to reflect the system-wide nature of the IRP analysis. Surely if degradation factors can be developed using professional judgement then it must be possible to develop estimates of potential avoided T&D costs.

The Director believes that improved EE (and other DERs) analysis will require sub-hourly load information to develop load shapes and EE bundles that better reflect the time and locational value of EE. The development of hourly and sub-hourly load data to construct load shapes was briefly discussed at one of the stakeholder sessions (*I&M's IRP, pages 84 and 85*). Since the IRP rule requires that all forms of resources, including EE and other DERs, are treated as comparably as possible, it is essential that the methodology to develop improved load information for EE and other DERs is clear and there is requisite empirical data to support the analysis. I&M-specific AMI load data is critical but so will be use of data currently being developed by national labs and other entities. This type of information will also be helpful to understand how the time value of EE changes as other DERs become more prevalent on the I&M system.

Demand Response (DR) and other DER modeling

I&M did not place significant effort in evaluating DR programs and even less in anticipating the development of and potential for other DERs to affect I&M's contribution to the PJM system peak demand and PJM's operations. In large part, the lack of DR is likely due to very low avoided costs. Even if T&D costs were included in I&M's avoided cost calculations, it might not move the needle and justify significantly more DR. The paucity of DR and other DERs may also be influenced by the lack of financial incentives from the PJM, and the failure to reflect time-varying costs of providing electric service in retail rates.

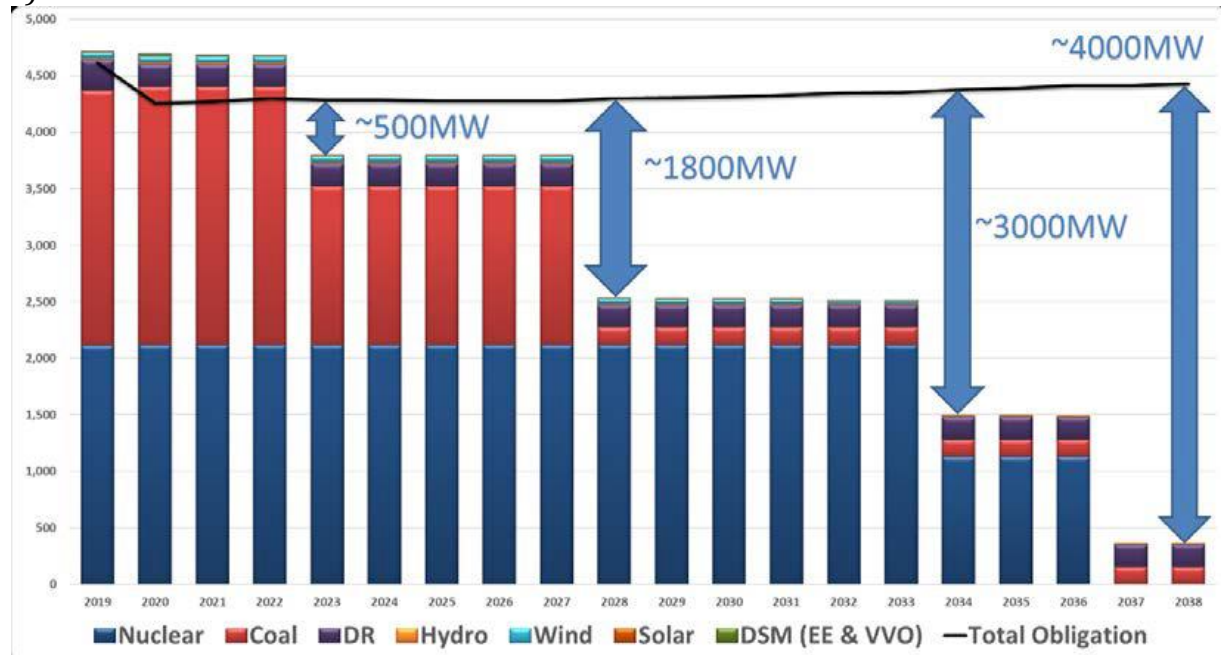
It seems likely that future IRPs will show increasing diversity of resources which may alter traditional concepts of resource adequacy and the calculation of avoided costs. I&M recognized the increasing proliferation of distributed generation (DG), to a large extent, is a function of customers' perception of their electricity costs. (*I&M IRP, pages 55 and 56*) This same observation necessarily applies to the speed with which other DERs are adopted. It is also possible that electric vehicles (EVs) will change the timing and amount of I&M's contribution to the PJM system peak and its operations.

The changing resource mix caused by an increasing penetration of DERs and corresponding changes in load shapes are also likely to affect I&M’s distribution system operations and planning in a variety of ways and, in some instances, the changes will be unanticipated. It seems probable that distribution system reliability will, increasingly, be a year-round concern that is accelerated by the changing resource composition, including the ramifications of DERs and EVs.

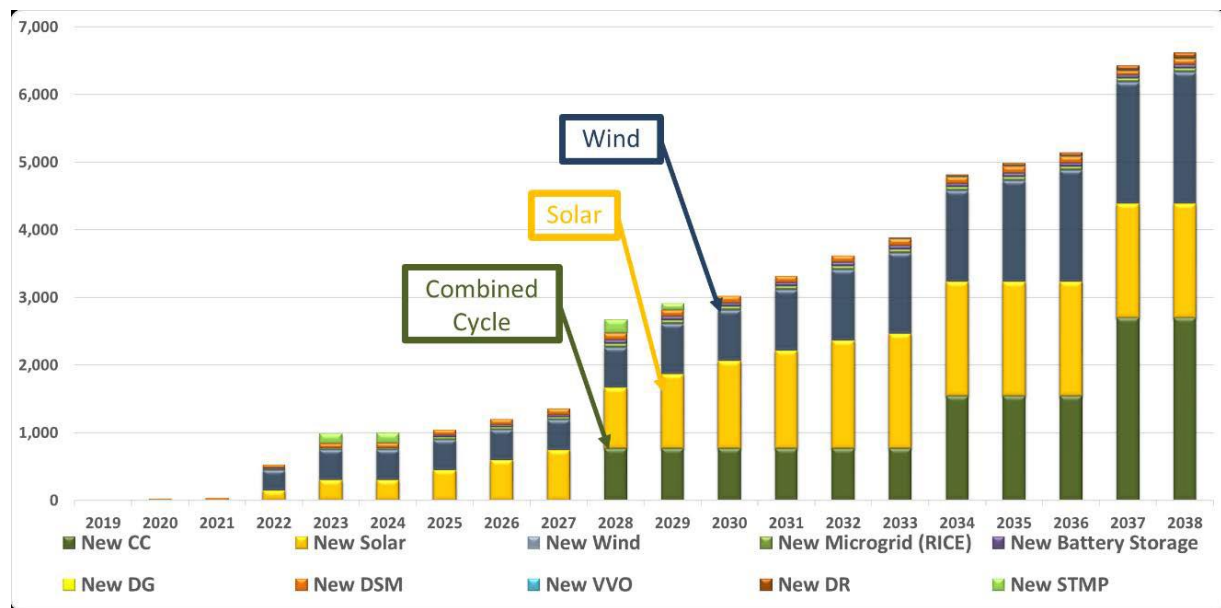
As EVs and a diverse group of DERs become increasingly significant, the ramifications on system load and load shapes must be closely evaluated to understand how the affects influence not just distribution system planning and operations, but also the bulk power system. The interactions of EVs and various DERs will affect the value of specific types of DERs. Improved load shape data will be a necessity but its importance will depend on how rapidly additional DER and EV load is added, their operational characteristics, and where they are located. Effective development of this information will involve a level of company-specific information combined with data available from other sources such as the national labs.

C. RESOURCE OPTIMIZATION AND RISK ANALYSIS

I&M states on Figure ES-1 below, “I&M’s assumed “going-in” capacity position (i.e. before resource additions) over the planning period, Through 2022, I&M’s existing capacity resources meet its forecasted internal demand. In 2023, I&M anticipates experiencing a capacity shortfall, 484MW, based upon its assumption of the expiration of the lease of Rockport Unit 2. This capacity shortfall is anticipated to increase to 1,762 MW in 2028 upon the retirement of Rockport Unit 1. The retirement of Cook Unit 1 in 2034 and Cook Unit 2 in 2038 further increases I&M’s capacity shortfall to 4,060MW.” (I&M’s IRP, page ES-4)



I&M believes it has identified a diverse set of resources to address the capacity deficit position over the planning period. (I&M IRP, Figure ES-2 and Table ES-1 on page ES-6) These additions, which include solar, wind, natural gas, energy storage, and EE resources, along with Short Term Market Purchases (STMP,) are expected to eliminate the capacity deficit through the planning period. (I&M IRP, page ES-5)



More specifically, the Preferred Portfolio includes the following resources. The Rockport Unit 2 lease expires at the end of 2022 and this IRP analysis suggests that retirement of Rockport Unit 1 will occur at the end of 2028. The continued low cost of natural gas, compared to the price of coal, influenced I&M's resources decisions with the possibility of integrating 2,700 MW of natural gas combined cycle (NGCC) generation including 770 MW in 2028 to replace the existing Rockport units, 770 MW of NGCC generation to replace the Cook Unit 1 in 2034, and 1,155 MW of NGCC in 2037 to replace Cook Unit 2 at the end of their current license periods. I&M also recognized the sharply declining cost of renewable resources, which suggested I&M integrate over 3,600 MW of wind and utility scale solar by 2038. I&M's IRP indicates that 50 MWs of batteries and 54 MW of micro grids might be installed by 2028. I&M also recognized the increasing contribution of other DERs including roof top solar, distributed generation (DG) as well as 180 MW of EE and DR. (I&M's IRP Public Summary, page 4)

I&M used the Plexus LP optimization model as the basis for resource portfolio modeling. I&M analyzed 24 scenarios for this IRP in order to test resource selection across varying commodity price and load conditions. The 24 scenarios were divided into five groups and optimized. Group 1 scenarios assumed retirement of Rockport 1 at the end of 2028 and lease termination of Rockport 2 at the end of 2022. A combination of base, high, low, and no carbon commodity price conditions were tested in Group 1. Group 2 scenarios were developed to better understand the dynamic resource selection based on various future

conditions related to Rockport 1. Base and No Carbon commodity pricing conditions were modeled all under base load forecast conditions. Battery storage and Mini-Grid resources were embedded in the analysis. Group 3 scenarios were developed to better understand specific resource constraints and their impact on resource selection. Various cases of NGCC additions were modeled and two cases with high levels of renewables were included. Group 4 scenarios considered resource selection based on various load and commodity price combinations. Group 5 consists of additional stakeholder-requested options.

For stochastic risk analysis, I&M compared the preferred portfolio to three other optimized portfolios. The three were Case 1 – the Base Case Optimization, Case 7 – Rockport Unit 1 having a Flue Gas Desulfurization (FGD) added in 2029 and retiring year end 2044, and Case 12 – High Renewables. The input variables subject to stochastic treatment were natural gas prices, PJM energy prices, blended coal prices, high sulfur coal prices, and carbon prices. For each resource portfolio, 100 random iterations were conducted.

DIRECTOR’S COMMENTS – RESOURCE OPTIMIZATION AND RISK ANALYSIS

For I&M, the status of the Rockport units is the keystone to I&M’s IRP and affects the near-term and long-term resource decisions with substantial attendant risks. After the status of the Rockport units become more certain, for future IRPs, I&M should be in a position to better identify future reliability, resilience, and economic risks and the attendant costs of their uncertainty beyond the Net Present Value of Revenue Requirements for the scenarios I&M evaluated. The Director appreciates that this IRP was constrained because of litigation and ongoing negotiations. In an attempt to thoroughly analyze the potential resource options available within the limited Rockport options, the company optimized 24 scenarios. While extensive, the analysis is weakened because of several limitations.

1. It appears that I&M did not assess the potential ramifications of the closure of Rockport 1 prior to 2028 combined with lease termination at year end 2022 for Unit 2. Without this information, it is difficult to assess a full range of implications.
2. While 24 cases were developed for scenario optimization, the variations in key parameters were limited. For example, only four scenarios used something other than the Base Load forecast. Cases 1, 5, and 9 had small differences in the conditions modeled. Insights drawn from scenario analysis appear to be limited or are not clearly expressed in the IRP discussion. This is despite the discussion on pages 130 – 131 of the IRP report. Also, the use of 24 scenarios is overwhelming to understand what the results are and how they are interpreted.
3. The optimized portfolios were not compared with each other in an organized manner. No clear criteria was identified and used to evaluate the various portfolios.

4. The IRP document lacks a detailed description of how the Preferred Plan was chosen from the scenario analysis.
5. It is not adequately explained why cases 1, 7, 9, and 12 were selected for comparison and for the probabilistic risk analysis.
6. Why only consider the Revenue Requirement at Risk in the stochastic risk analysis?
7. Though the aggressive build out of renewables may not be practical for I&M in the short-term, the results from the optimization analysis show that adding more renewables would reduce the long-term revenue requirement risk. This type of result should have stimulated more analysis to better understand the trade-offs involved. For example, I&M could have removed the capacity limitation on renewables under preferred Case 9. It may have created a different resource portfolio which may be more economic than the current Case 9 portfolio.
8. It appears that I&M's IRP has an over abundance of wind resources in particular and solar which cause the preferred portfolio to be long on energy. The pricing projections in the scenario analysis seem to be driving these resource decisions. The Director presumes this is done to promote sales (off-system or to select customers). The Director would welcome I&M's comments on whether this is I&M's intention. Did I&M consider the extent to which the economics of various resource portfolios depended on wholesale power sales?
9. Finally, in its analysis of risks, I&M considered four commodity price scenarios ((i.e. Base, High Band, Low Band and No Carbon). I&M also analyzed the effects of a lower and upper band of forecasts to consider lower and higher North American demand for electric generation and fuels and, consequently, lower and higher fuels prices. Nominally, fossil fuel prices vary one standard deviation above and below Base Case values. (*I&M's IRP, page 79*) However, this limited risk analysis is not likely to capture the potential risk reductions caused by additional amounts of EE and DR in its preferred portfolio on its load forecast. Similarly, I&M has given little consideration to the potential for other DERs to further mitigate risks. One of the most significant on-going risks for I&M is assessing the value of reduced exposure to market price risk by integrating DERs along with other resources. This is not adequately evaluated by I&M embedding distributed solar in amounts equal to a CAGR of 10.3% over the planning period. (*I&M IRP, page 116*) The Director also believes I&M should consider the potential risk ramifications of increased penetration of EVs within I&M's service territory.

D. THE STAKEHOLDER PROCESS

I&M had an improved (or thorough) stakeholder process. I&M conducted four stakeholder meetings beginning on Feb. 15, 2018. The next meetings were April 11, 2018, Feb. 21,

2019, and May 22, 2019 (*I&M IRP, page 6*). Several conference calls, one-on-one meetings, and numerous email correspondence occurred throughout the process. I&M started the process early to accommodate the stakeholders' requests which resulted in greater stakeholder participation, and I&M also made a concerted effort to increase the diversity of stakeholders. I&M made its subject matter experts available to the stakeholders.

As a part of its effort to facilitate stakeholder participation, I&M provided Citizens Action Coalition (CAC) Joint Commenters access to a read-only license for Plexos. This enabled CAC to access model inputs and outputs along with a model manual which aided CAC's understanding of how Plexos works. I&M staff also held multiple meetings on the model with CAC and its consultants and readily answered questions about the model. CAC found this process had limitations but substantially improved its review of I&M's IRP. (*CAC Joint Comments, pages 6 and 7*)

The IRP Schedule Changes

During the IRP development process, I&M sought and was granted three schedule extensions. The first extension request, made on July 26, 2018, extended the filing deadline from Nov. 1, 2018 to Feb. 1, 2019. The reason for the request was to allow additional time for the United States District Court for the Southern District of Ohio ("Court") to rule on a Jan. 8, 2018, Supplemental Motion prospering the Fifth Modification of Consent Decree ("Motion"). The Rockport Plant which is a two-unit, 2,600 MW coal-fired generation facility located in Spencer County, Indiana, is subject to the Consent Decree that resolved a Clean Air Act suit. If granted, the Motion would change the Consent Decree provisions applicable to the Rockport Plant and, therefore, may substantially affect I&M's resource plans. The Motion had not yet been ruled on by the Court at the time of the extension request and the final resolution is still pending at the time of this filing.

The second request, made on Oct. 26, 2018, extended the filing deadline from Feb. 1, 2019, to May 1, 2019. The cause for the request was to allow I&M time to complete the modeling necessary to provide I&M and stakeholders a meaningful opportunity to review the results ahead of the next stakeholder meeting.

The third extension, requested on March 18, 2019, moved I&M's IRP filing date from May 1 to July 1, 2019 to provide additional time to incorporate updates and changes to forecasted inputs and to assess the impact of those changes on the modeling results. (*I&M IRP, page 6*)

IV FUTURE ENHANCEMENTS TO I&M'S IRP PROCESSES

The Director appreciates the modifications that I&M has made in response to the 2015 Director's Report (*I&M IRP, page ES-3*):

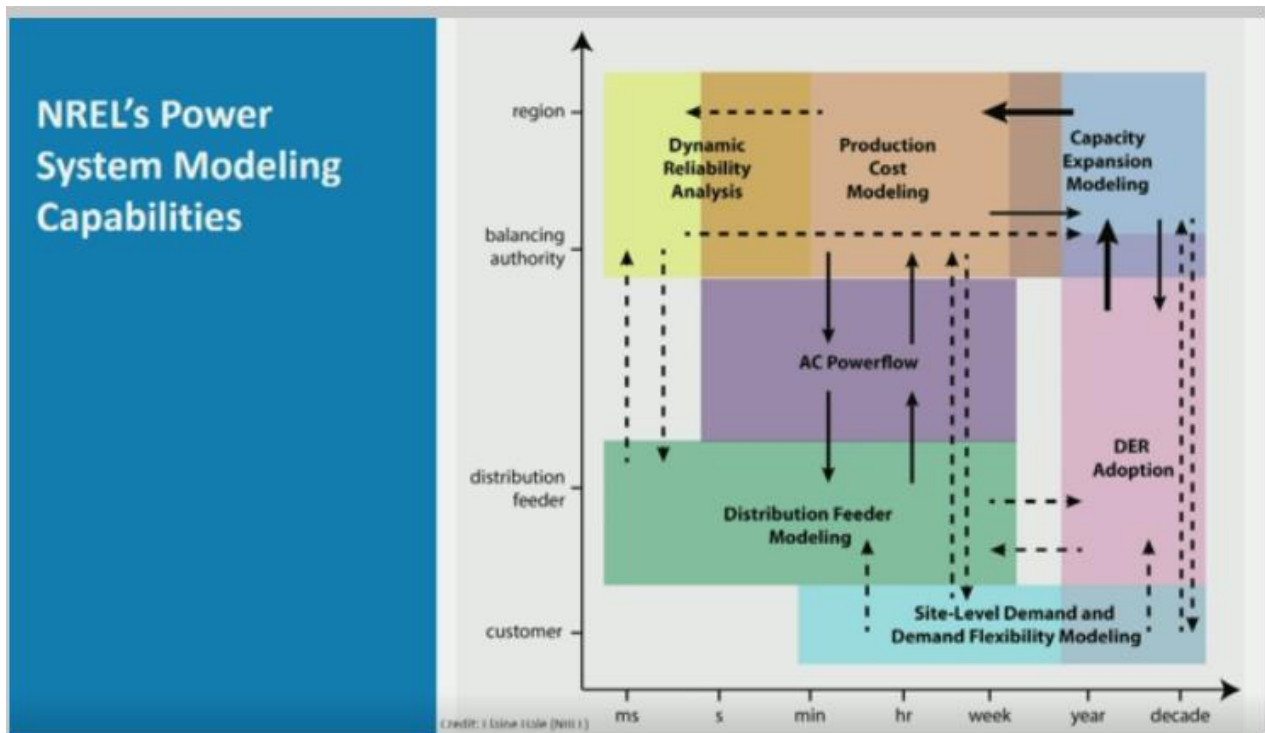
- 1) Uses the most recent load forecast which shows a reduced need for capacity over the 20 year planning horizon. Having a greater range of load forecasts was helpful;

2) Incorporates the most recent fundamental forecast developed in 2019; includes updated projections of costs for renewable resources based on Bloomberg’s New Energy Finance’s (BNEF) H3 2018 U.S. Renewable Energy Market Outlook;

I&M’s recognition that, in addition to avoided generation costs, there are also distribution and transmission system avoided costs, should prompt an effort to quantify or approximate the full avoided costs by time and location as a means of reducing distribution system expenses (recognizing that a significant degree of transmission related costs are RTO driven and thus FERC jurisdictional) and improving the reliability and economic efficiency of the distribution system. To say that the avoided costs are zero merely because they are difficult to quantify is excessively cautious.

The distribution system must have the capacity to safely and reliably distribute central generation resources to end use customers and must accommodate distributed resources as well, whether owned by the Company or by other entities including end use customers. Accordingly, expansions of the distribution system are highly location-specific and dependent upon the unique circumstances of load, interconnected transmission, and connected generation within a local distribution planning area. The concept of distribution-related avoided cost is location specific, based on the load and resource attributes of the specific area under consideration. *(I&M IRP, page 95)*

The NREL graphic below is illustrative of the evolution of IRP to include Distribution System Planning and operations and RTO planning and operations.



I&M's ongoing use of state-of-the-art software is commendable. The Director trusts that I&M continues to assess the evolution of state-of-the-art models and the appropriate data bases required to gain maximum benefits from the advances in modeling,

As stated previously, the Director would like I&M to provide an update in the next IRP process on how I&M intends to fully utilize its data from advanced metering infrastructure, or AMI (software, hardware, and types of information such as load shapes for a variety of different types of customers). This should include the development of a variety of customer load shapes that are more homogeneous than rate classifications. In addition to engaging stakeholders, the Director recommends that I&M engage outside experts (e.g., the National Laboratories). To the extent that the load shapes provide useful information to evaluate EE, DR, and other DERs that can benefit the PJM, I&M may wish to invite PJM to participate in this process.

To improve I&M's load forecasting (including projections of DERs and EVs), more accurate design of rates and programs for DERs, enhanced resource planning, and improving distribution system planning, the Director urges I&M to develop short-term (e.g., 3 years) and longer-term (e.g., 6 years) plans to integrate AMI data that is supplemented with:

- A) End-use load research on selected appliances / end-uses on a sub-hourly basis. This should include data on DERs and EVs;
- B) As part of I&M's on-going load research, I&M should conduct regular customer surveys (every three years or so). These should be robust random representative samples of residential and commercial customers to add increased credibility to I&M's load forecast. This information should provide insights into the degradation analysis of EE and how customers perceive DERs in general. This survey data should help I&M gain a more holistic understanding of its customers for forecasting, rate design, DSM, and EVs. The information should involve surveyors that have sufficient expertise to obtain appliance/end-use information that details the age, connected load, condition, housing stock/building information, and demographic data. I&M may want to coordinate with other utilities, the National Laboratories, the Energy Information Administration, etc;
- C) Obtain sub-hourly load data and information on distributed energy resource customers, including battery storage and any new technology. Coordination with PJM seems appropriate;
- D) Obtain and maintain commercial customer identification using the North American Industrial Classification System (NAICS) to supplement AMI and survey data;
- E) Develop a variety of load shapes based on sub-hourly load data that is predicated on a variety of parameters to develop groupings of customers that are more homogenous (e.g., intra-rate class, different usage levels, customers with different types of appliances/end-uses, customers that have different types of DSM, etc.);

- F) Develop a more comprehensive approach to avoided costs so that DER evaluation is more accurately based on credible estimates of valuation by time and location. Explore with PJM how DER may be better integrated into PJM's and I&M's planning and operations.
- G) Especially with greater reliance on DERs, increasing penetration of EVs and charging stations, and integration of renewable resources, there is an impetus for greater integration of distribution system planning with I&M's IRP, as well as RTO planning and operations. This will require greater involvement with PJM which may include collaborative programs that may be mutually beneficial such as projecting the implications of DERs on both the distribution system planning and operations as well as PJM's planning and operations.
- H) I&M should also keep track of load shape changes for the system, classes of customers, and groups of customers within a rate class.

Each future IRP should explicitly address the progress on the plan for continued improvements. Because IRP's address both the short and long-run resource assessment, it is essential that the plan address the rate structure changes that are consistent with the strategic plan.

V. STAKEHOLDER COMMENTS

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

The public input to I&M's IRP has been gratifying. The stakeholder process, despite concerns that it could have been more responsive, deserves much of the credit. The following comments are intended to be a representative sampling of the public input into I&M's 2018-2019 Integrated Resource Plan and stakeholder process. Often similar comments raised by more than one commenter. To reduce redundancy, the Director selected some of the more salient and representative commentary.

Clean Grid Alliance (CGA)

CGA's comments address the following points: [1] I&M's ability to meet customer demand and encourage economic development by accelerating renewable development; [2] the importance of third-party data to confirm the cost-effectiveness of renewable generation; [3] the benefits of an "All Source Request for Proposals" on an annual basis; [4] the benefits of I&M's plan to procure a balanced mix of renewable generation; [5] the importance of a well-designed green tariff program; [6]; the reasonableness of I&M's resource planning

models; [7] to reasonably account for higher penetrations of renewable resources through hourly and sub-hourly system modeling; [8] to I&M's commitment to battery storage; and [9] the need for transmission planning to deliver electricity from its forecasted generation to its customers at the lowest overall production cost of electricity.

Director's Comments: *At the outset, as an economic regulator, the IURC does not advocate for specific resources. Rather, the IURC's statutory charge is to ensure reliability at the lowest delivered cost reasonably possible. This dual responsibility is, therefore, central to the integrated resource planning rules.*

We agree with CGA that retaining optionality to the extent reasonably possible is appropriate. As CGA correctly states, the possible addition of natural gas-fired generation in this IRP does not, in any way, obligate I&M to any particular resource decisions. The Director disagrees with CGA that "I&M should advance its renewable purchasing earlier in the plan...to obviate the need to build more expensive gas generation in the later years of the plan...". (CGA Comments on I&M IRP, page 4) Building or buying resources that are in advance of the customers' needs may result in higher prices in excess of benefits. It must be considered that the early acquisition of significant renewable resources itself may unreasonably reduce optionality. Also, we cannot know today how the engineering performance and economics of different resource options will change, especially relative to each other, over a number of years.

Both NIPSCO and Vectren have made a compelling case for requests for proposals (RFPs) being integrated into their IRPs because the RFPs are intended to result in contracts to buy or build resources to meet near term service and reliability requirements in an economically efficient manner. The several respondents to the all-source RFPs provide excellent price and performance data for the IRPs and, in many cases, vendors provide the delivered cost of electricity that accounts for transmission, congestion, and other transaction costs that are not, always, included in the vendors' proposals. However, RFPs that are not actionable (meaning there is no intent to acquire resources in the near term resulting from the RFP), but are merely used for price discovery for planning purposes, may not result in vendors revealing their true costs. Moreover, this use of an RFP-type process may reduce the number of vendors expressing an interest in responding to actionable RFPs. For these reasons, the RFP should be actionable as a source for better cost information.

This Director's Report and previous Director's Reports have urged I&M and all Indiana utilities to utilize advanced Metering infrastructure (AMI) to develop hourly and sub-hourly load shapes to facilitate the integration of renewable resources and all forms of DERs. I&M is installing AMI and the Director expects I&M to improve its planning processes by making effective use of the load data made available through AMI.

Indiana Advanced Energy Economy (AEE)

Indiana AEE makes four main points: 1) I&M could realize greater savings by deploying more renewable and storage resources and accelerating its development timeline; 2) It should also do this to account for growing, near-term commercial and industrial demand; 3) Demand side resources, such as EE and DR should be more heavily incorporated into this IRP; and, 4) The Commission should closely scrutinize I&M's plan to invest in combined cycle gas plants instead of cost-effective advanced energy alternatives, especially in 2034 and 2037.

Director's Comments: *AEE's comments on accelerating the acquisition of renewable resources are generally consistent with the Clean Grid Alliance and the CAC Joint Commenters' concern about the level of EE. More specifically, AEE believes that I&M used cost data for DERs that are too high which results in a resource plan that is not as cost-effective as it could be. The IRP rule requires utilities to treat EE, DR, other DERs, and renewable resources, on a comparable basis to traditional generation, to the extent reasonably feasible.*

The Director is thoroughly familiar with the debate about the projected costs of different resources over a 20-year planning period. Not only is there a problem projecting the cost trend of any given technology, but there is the greater complication of projecting the relative costs of numerous resource options over the planning period. There is simply no way to know which projected specific cost or price trajectory is correct. This is the definition of uncertainty. The only way to address this question is to use a range of prices or cost trajectories for the various resources to better understand how this uncertainty impacts resource selection over the planning period. This is an area in which all utility IRPs have improved but need to strive for continuous analytical improvement.

For example, the Director would like to see more analysis devoted to understanding or trying to quantify the sensitivity of EE selection in the optimization process to changes in the projected costs of EE. This could also be done with other DERs and renewables more generally. The extent of sensitivity would highlight areas that need to be monitored closely when making resource commitments in the near to middle term.

Indiana Coal Council (ICC)

The Indiana Coal Council offered several concerns. 1) I&M has not justified the need for the Fifth Modification to the Consent Decree. 2) I&M failed to adequately analyze the potential for extending the Rockport 2 lease and thus undervalued this option. 3) ICC suggests that I&M should have evaluated the efficacy of extending the life of Rockport beyond 2028. 4) I&M has improperly failed to account for the incremental transmission costs and congestion costs in the context of portfolio alternatives before committing to large-scale reliance on utility-scale renewable resources. 5) I&M failed to fully consider the life cycle emissions of any possible future commitment to new natural gas generation facilities

The Director's Comments: *The Director sees many of these criticisms of I&M's analysis as being similar to the Director's criticisms of I&M's scenario and uncertainty analysis discussed earlier in this document. The analysis presented by I&M is not as thorough as it might initially appear. The Director believes there is room for considerable improvement by I&M, but also believes I&M artificially constrained its review to avoid putting in a public forum critical information that might hinder negotiations regarding the possible extension of the Rockport 2 lease.*

Indiana Office of Utility Consumer Counselor (OUCC)

The Director appreciates the OUCC's comments and concerns regarding I&M's IRP. The Director will summarize those comments as follows: 1) Concern about excess capacity if I&M constructs 2700 MW of natural gas combined cycle; 2) A concern that the generating capacity in I&M's Preferred Plan may preempt DSM and other distributed energy projects; 3) The pricing of distributed resources and renewables needs to be re-examined considering: (a) expiring federal tax credits and (b) actual market prices, 4) I&M has not finalized its obligations for Rockport to comply with Combustion Residuals and Effluent Limitation Guidelines; 5) Concern that utilities will delay their IRPs to coincide with filing of rate cases or Certificate of Need cases (CPCN) and, deprive stakeholders of information from the Director's Report and other analysis; 6) A lack of transparency regarding the Consent Decree and the status of the Rockport units; 7) Whether the Rockport 2 unit could operate longer than 2028 if it is economical to do so; 8) The feasibility that DSI might extend the useful life of the Rockport units; 9) The lack of an assessment of an extension of the Rockport 2 lease or reserving a portion of output under a PPA if economical.

The Director's Comments: *With regard to the OUCC's Question 1, I&M's resource plan is overwhelmingly influenced by the disposition of the Rockport units that indicate a 2028 retirement (I&M IRP, page ES-2) which coincides with I&M's potential need for other resources. Since I&M's projections for large combined cycle units are several years out, they should be regarded as illustrative of the potential need for resources but not as a fait accompli. I&M's statements that they will maintain as much optionality as possible and consider developing technologies is appropriate.*

At this time, the Company considers...combined cycle configurations to be the best fit as they most align with historical operating experience and expected output relative to the overall Company's needs. (I&M IRP, page 99)...Most importantly, the Preferred Plan does not include a significant investment in new natural gas combined cycle resources until 2028, allowing I&M to modernize its grid and explore new or developing technologies to meet its future capacity obligations." (I&M IRP, Table 27 on page 131)

Table 27. Cumulative Capacity Additions (MW) for Preferred Plan

	Commodity Pricing	Resource																					
			2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	
Case 9 (Preferred)	BASE	New Solar Firm				76	153	153	229	305	381	458	559	661	737	814	865	865	865	865	865	865	
		New Solar				150	300	300	450	600	750	900	1100	1300	1450	1600	1700	1700	1700	1700	1700	1700	1700
		New Wind Firm				37	55	55	55	55	55	74	92	92	111	129	148	166	185	203	221	240	240
		New Wind				300	450	450	450	450	450	600	750	750	900	1050	1200	1350	1500	1650	1800	1950	1950
		New DG Firm				10	12	15	16	17	17	19	20	22	24	25	28	30	31	33	35	36	36
		New Microgrid (RICE)				18	18	18	36	36	36	54	54	54	54	54	54	54	54	54	54	54	54
		New CT																					
		New DSM		19	36	50	62	71	81	89	97	105	96	102	101	101	101	100	102	97	61	86	86
		New VVO															9	9	9	9	9	9	9
		New Battery Storage				10	10	10	30	30	30	50	50	50	50	50	50	50	50	50	50	50	50
		New CC											770	770	770	770	770	770	1540	1540	1540	2695	2695
		New STMP						150	150				200	100									
		New DR															14	29	43	58	72	86	86

Many of the OUCC's comments address limitations in I&M's scenario and risk analysis. The Director believes many of these limitations were self-imposed to address any potential adverse impact on I&M's legal strategies involving the Fifth Modification to the Consent Decree and negotiations involving an extension of the Rockport 2 lease. The self-imposed limits might have been reasonable given I&M's circumstances but it undoubtedly hampered the usefulness of the IRP process. As the Director noted above, the portfolio and risk analysis is not what it should have been.

The OUCC also expressed concern with the trend of Indiana electric IOUs delaying IRP filings to coincide with the filing of a rate case or a certificate of public convenience and necessity (CPCN) filing. (OUCC Comments on I&M IRP, page 2)

The Director appreciates that filing cases for changes in rates, DSM programs, and Certificate of Need cases that are roughly contemporaneous with the submittal of IRPs and the review by stakeholders and the Director's Report, pose real concerns. In the past, particularly with DSM programs, stakeholders expressed concerns that the IRPs were stale and could not provide information necessary to be relied upon. There may also be instances where time is of the essence and the proximity in time between an IRP submittal and a case is unavoidable. Obviously, there is a need to strike a balance. However, this should be a matter for the Commission to decide on a case-by-case basis.

Citizens Action Coalition (CAC), Carmel Green Initiative, Earthjustice, IndianaDG, Sierra Club, and Valley Watch (Referred to as "CAC Joint Commenters")

The CAC Joint Commenters summarize their concerns on Table 1 Page 4 as follows:

- 1) Energy efficiency potential was unreasonably constrained
- 2) Significant build constraints were placed on renewables;
- 3) Wind costs were modeled at higher prices than is justifiable;
- 4) Solar costs were modeled at higher prices than is justifiable;
- 4) I&M used an unrealistically low capital cost for gas combined cycled units;
- 4) I&M did not consider retirement options for all of its coal units;
- 5) Three 18 MW reciprocating internal combustion engine ("RICE") units were forced in to evaluate "Mini-grid" resources and may have unreasonably depressed the selection of EE;
- 6) Scenarios and portfolios were conflated in ways that missed important

areas for analysis; and 7) I&M's stochastic analysis is fatally flawed and cannot be relied upon for risk assessment.

Director's Comments: *The CAC Joint Commenters state that I&M undervalued EE by distorting the avoided costs. The Director disagrees in part and agrees with CAC Joint Commenters in part. That is, I&M's use of the PJM energy and capacity markets as a proxy seems to be an appropriate estimation of avoided costs as far as it goes. As I&M correctly states, the complexities of the T&D system pose a daunting task to give effect to the avoided T&D costs. However, the Director believes that an evolutionary effort to quantify avoided T&D systems costs are in the public interest. In sum, trying to capture the dynamic costs of the bulk power market and the avoided T&D system costs should be the objective.*

The CAC Joint Commenters advocate the use of a "decrement" approach to modeling EE. (CAC Joint Commenters Comments on I&M IRP, page 9) The Director appreciates the intellectual effort to develop the decrement method but does not believe that a prima facie argument has been made that this approach is superior to I&M's modeling of EE. In recent Director's Reports, the Director has expressed concerns with both approaches but also recognizes that, currently, there is no obviously superior methodology. The Director believes that the CAC Joint Commenters and I&M agree that any method should enable EE to be evaluated on as comparable a basis as possible with other DERs and all other resources, which is a limitation of both approaches. As utilities integrate data from advanced metering infrastructure into their planning processes, there may be opportunities for advancement in EE (and other DER and EV modeling) using sub-hourly load shapes and supporting information to better reflect the dynamic changes in the value (avoided costs) of all DERs and other resources.

The Director believes the analysis of EE had many conceptual complications that warranted more discussion. Chief among these conceptual complications were the development and application of degradation factors and how EE bundles considered other DSM measure characteristics beyond costs. However, the Director cannot overlook the fact that avoided costs are a significant driver of EE selection and similarly for other DERs, and that avoided costs used by I&M in the IRP decreased significantly from the 2015 IRP. This decrease seems reasonable given the changes in the PJM marketplace. As noted earlier, the Director would like to see more analysis of how sensitive resource selections are to changes in the cost of EE bundles and other DERs.

The CAC Joint Commenters contend that the results from NIPSCO's all-source request for proposals (RFP) provides a more accurate assessment of resource costs. (CAC Joint Commenters' Comments, page 9) The Director has some sympathy with that contention. However, it should be noted that, at least one developer in the NIPSCO RFP was not able to deliver the resources at the prices in its bid. Secondly, the RFP is a snapshot of prices and price adjustments – up or down – should be expected. Vectren, for example, encountered higher prices in its RFP than NIPSCO. In prior IRPs, the

Director gives considerable discretion to the utility management in assessing the cost of various types of resources, particularly traditional generation. Utilities should, however, be cognizant of the pricing dynamics of these resources. Correspondingly, advocates of greater reliance on renewable resources need to consider the concerns that integration of intermittent renewable resources currently pose reliability and economic concerns.

The CAC Joint Commenters asked I&M to explain how it will own and operate the microgrids/mini-grids and how this would be distinguished from the RICE units serving as peaking resources. (CAC Joint Commenters' Comments, page 24) In response to an informal data request CAC Data Request 3.16), I&M stated: "I&M intends to own and operate the micro grid resources. Each micro-grid will include uniquely configured generation resource(s) and distribution investments to allow the sectionalizing of the distribution system..."

I&M's recognition of the need for coordinated distribution system planning with IRPs and the wholesale markets is a significant advance in I&M's (and the industry in general) planning. The Director agrees with the CAC Joint Commenters that I&M should engage stakeholders to better ensure these resources are cost-effective and enhance economics, reliability/resiliency.

The CAC Joint Commenters raised concern that in no scenario were the retirements of both Rockport Units 1 and 2 optimized. And in no scenario could the model choose to exit from the Ohio Valley Electric Corporation ("OVEC") contracts for Clifty Creek and Kyger Creek coal units. (CAC Joint Commenters' Comments, page 24)

The Director acknowledges that, ideally and under best practices, I&M should have modeled these units on a comparable basis to all generating units. However, given the significant legal concerns about the future status of the Rockport units, at the time I&M submitted its IRP, I&M was unable to model these facilities. Similarly, there are complicated contractual issues with OVEC prevented modeling. Future IRPs should not be as constrained.