INTEGRATED RESOURCE PLANNING REPORT

TO THE

INDIANA UTILITY REGULATORY COMMISSION

Submitted Pursuant to

Commission Rule 170 IAC 4-7

July 1, 2019

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Executive Summary

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 developed this IRP in accordance with the requirements of 170 IAC 4-7. The locations within this IRP filing that address the specific Indiana filing requirements are summarized in the Exhibit G of the Appendix.

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 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 has analyzed various scenarios that would provide adequate supply and demand resources to meet its projected peak load obligations, and reduce or minimize costs to its customers, including energy costs, for the next twenty years. Following are the key components and inputs of I&M's Preferred Plan:

- Continue operation of the Cook units through the remainder of their current license periods;
- The Rockport Unit 2 lease expires at the end of 2022 and Rockport Unit 1 is retired at the end of 2028;
- Continue deployment of supply-side renewable resources including the addition of over 3600 MW of wind and large scale solar by 2038, beginning in 2022;
- Incorporate 50MW of Batteries and 54MW of Micro/Mini-Grid resources by 2028;
- Add 2,700MW of Natural Gas Combined Cycle (NGCC) generation including 770 MW in 2028 to replace Rockport capacity, 770MW in 2034 to replace Cook Unit 1 and 1,155MW in 2037 to replace Cook Unit 2 at the end of their current license periods;
- Incorporates demand-side resources including 180MW of Energy Efficiency (EE) and Demand Response (DR) and
- Recognizes that residential and commercial customers will add distributed resources, primarily in the form of residential and commercial rooftop solar (i.e. Distributed Generation [DG]).

Key Changes from 2015 IRP

This IRP includes the following changes from the Company's 2015 IRP:

- Incorporates the most recent load forecast, which shows a reduced need for capacity additions over the forecast period, and a minimal change in energy needs.
- Incorporates the most recent fundamental commodity forecast developed in April 2019.
- Incorporates updated renewable cost information primarily based upon Bloomberg New Energy Finance's (BNEF) H2 2018 U.S. Renewable Energy Market Outlook.
- Incorporates recommendations from the Directors August 20, 2016 Final Report on 2015-2016 integrated resource plans and other reports and input from the Director and staff on opportunities for continued improvement in the IRP process.

- Enhanced the public advisory process and provided opportunities for greater stakeholder involvement in the development of assumptions, scenarios and sensitivities, making the IRP more meaningful for stakeholders.
- Improved clarity and explanatory value of the IRP report.

Summary of I&M's Resource Plan

I&M's retail sales are projected to grow at 0.1% per year with stronger growth expected from the industrial class (+0.4% per year) while the residential class remains relatively flat and the commercial class experiences a decline (-0.3% per year) over the forecast horizon. I&M's internal energy and peak demand are expected to decrease at an average rate of 0.2% and 0.2% per year, respectively, through 2038.

Figure ES-1 below shows I&M's assumed "going-in" capacity position (i.e. before resource additions) over the planning period, which uses the PJM summer peak to determine resource requirements. 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 1,762MW 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.

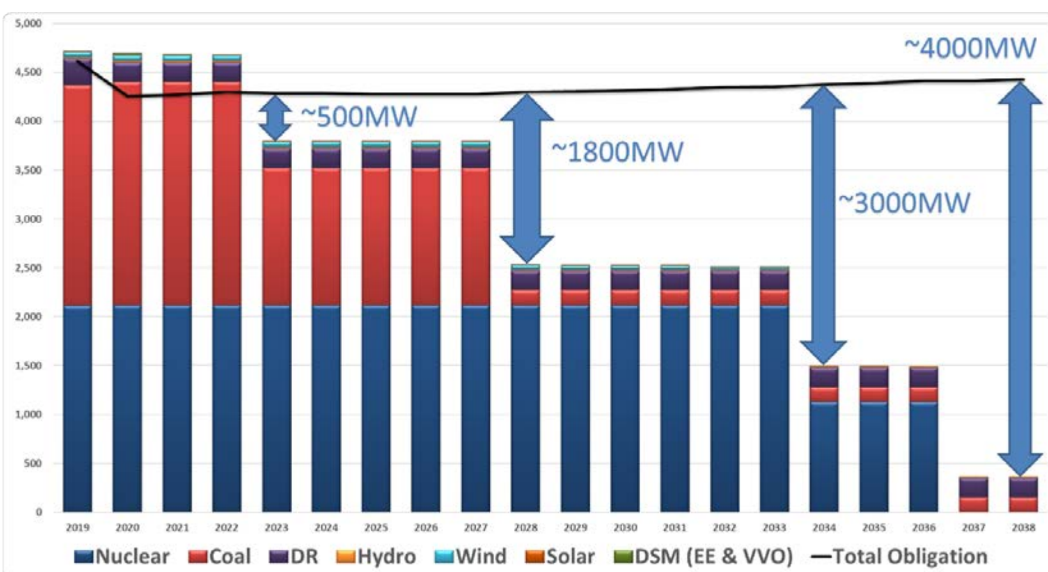

Figure ES- 1. I&M "Going-In" Position

I&M has identified a diverse set of resources to address the capacity deficit position over the planning period. (Figure ES-2 and Table ES-1) These additions, which include solar, wind, natural gas, energy storage and energy efficiency resources along with short-term market purchases (STMP) , are expected to eliminate the capacity deficit through the planning period. The solar resources are assumed to provide PJM capacity equal to 51.1% of their nameplate rating (or 102MW for 200MW of nameplate solar) and wind resources are assumed to provide PJM capacity equal to 12.3% of their nameplate rating (or 37MW for 300 MW of nameplate wind).

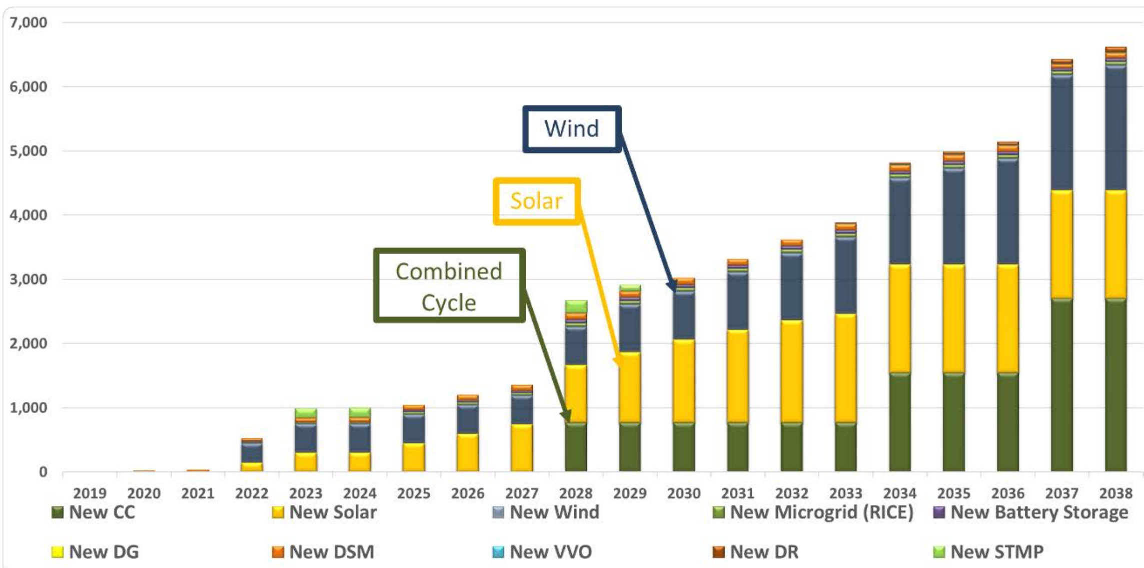

Figure ES- 2. I&M New Capacity Additions – Nameplate (MW)

The resource additions allow I&M to satisfy its PJM load obligations over the planning period. Additionally, EECO and customer owned generation such as rooftop solar will also improve I&M's capacity position.

To determine the appropriate timing of new resources, I&M used the Plexos® model to calculate the lowest cost resource addition portfolio under four commodity pricing scenarios, (i.e. Base, High Band, Low Band and No Carbon) also referred to as the Optimal Plan for a given commodity pricing scenario. To arrive at the Preferred Plan, I&M considered a resource mix that included attributes of the various Optimal Plans. A summary of the Preferred Plan costs and levelized customer bill impacts[1] relative to the Base plan and various alternative plans is shown in Table ES-1   Notably, the Preferred Plan is a flexible, balanced low cost plan over the 20-year IRP planning period, and moves the Company toward a more diversified resource fleet. This is accomplished by adding smaller, geographically diverse resources consisting of solar, wind, DSM, energy storage, microgrids and STMP during the first several years of the plan.

Table ES- 1. Preferred Plan cost comparison to optimum portfolios

	Cummulative Present Worth Cost over Case 1		Levelized Annual Bill Impact over Case 1 ($)	
	thru 2029	thru 2038	thru 2029	thru 2038
Case 1 - Base Optimization	-	-	-	-
Case 9 - Preferred Plan	$ 4,528	$ 22,878	$ 0.33	$ 1.16
Case 12 - High Renewables	$ 129,550	$ 64,410	$ 9.38	$ 3.38
Case 7 - Rockport U1 FGD 1/2029	$ 38,034	$ 684,774	$ 2.73	$ 34.82

Table ES- 2 provides a summary of the Preferred Plan cumulative resource additions. The Preferred Plan offers I&M significant flexibility should future conditions differ considerably from the underlying assumptions. A key feature of the Preferred Plan is that it defers the investment in large-scale natural gas combined cycle generation until 2028, giving I&M flexibility in the early years of the plan by meeting its PJM load obligation primarily with renewable wind and solar resources, energy efficiency, short-term market purchases and energy storage.

Table ES- 2. Preferred Plan Cumulative Additions from 2019 to 2038 (MW)

	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*
		New Wind Firm				37	55	55	55	55	55	74	92	92	111	129	148	166	185	203	221	240
		New Wind				*300*	*450*	*450*	*450*	*450*	*450*	*600*	*750*	*750*	*900*	*1050*	*1200*	*1350*	*1500*	*1650*	*1800*	*1950*
		New DG Firm				10	12	15	16	17	17	19	20	22	24	25	28	30	31	33	35	36
		New Microgrid (RICE)				18	18	18	36	36	36	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*
		New VVO															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
		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

[1] The Levelized Annual Bill Impact is an indicative estimate of the incremental cost compared to Case 1 – Base Optimization. This indicative estimate is only capturing the costs and benefits related to the proposed resource additions included in this IRP. The estimate assumes the impact to an "Average Customer" that uses 12,000 kWh per year.

Specific I&M capacity changes by resource type over the 20-year planning period associated with the Preferred Plan are shown in Figure ES- 3 and their relative impacts to I&M's annual energy position are shown in Figure ES- 4 and Figure ES- 5.

Figure ES-3 illustrates I&M's commitment to renewables and DSM over the planning period. The first nine years of the plan focuses on adding smaller, geographically diverse resources consisting of solar, wind, DSM, energy storage, microgrids and STMP. Consistent with the indicative nature of this IRP's proposed resource additions, the actual quantity of future renewable resource additions at a particular time depends, in part, on the specific resources available (and their cost) during a "resources acquisition" process. This will provide flexibility to acquire more or less of the IRP planned resources based on actual market conditions at those times. This flexibility may ultimately lead to a delay or the elimination of one or more of the combined cycle resources added over the planning period.

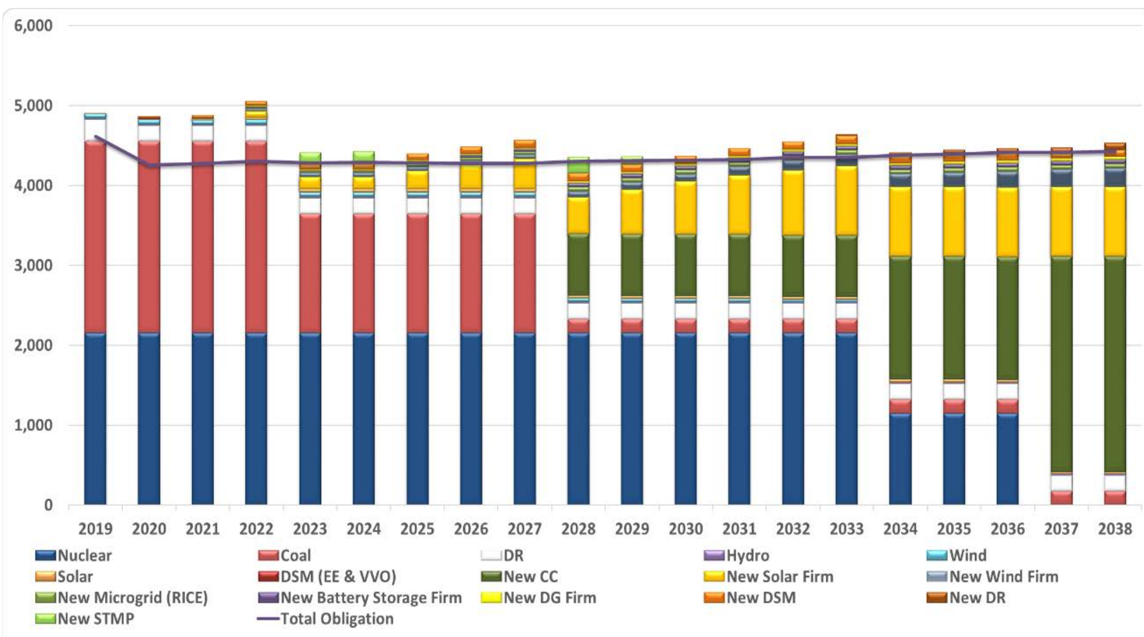

Figure ES- 3. Existing and New Capacity Additions – Firm (MW)

The capacity contribution from renewable resources is modest due to their intermittent characteristic; however, those resources (particularly wind) provide a significant volume of energy. Figure ES- 4 and Figure ES- 5 show annual changes in energy mix that result from the Preferred Plan over the planning period. I&M's energy output shows a significant transformation away from coal and nuclear while the energy output attributable to renewable generation (wind and solar) grows. The forecasted output by resource is based on the Company's modeling results as described in Sections 4 and 5. The results are best characterized as both a capacity planning and energy or dispatch cost solution. From the energy perspective a resource's output (energy) is based on its cost to generate relative to PJM market cost. When the Company's resources provide more energy than the Company's load obligation, the Company and its customers benefit from the margin on the energy produced (i.e. the difference between the PJM market price and I&M's cost to generate the energy). Put another way, this energy would only be produced when it was "profitable" to do so and should as a result lower the cost of the plan to customers. Energy from these renewable resources, combined with EE and EECO energy savings reduce I&M's exposure to PJM energy, fuel and potential carbon emission prices.

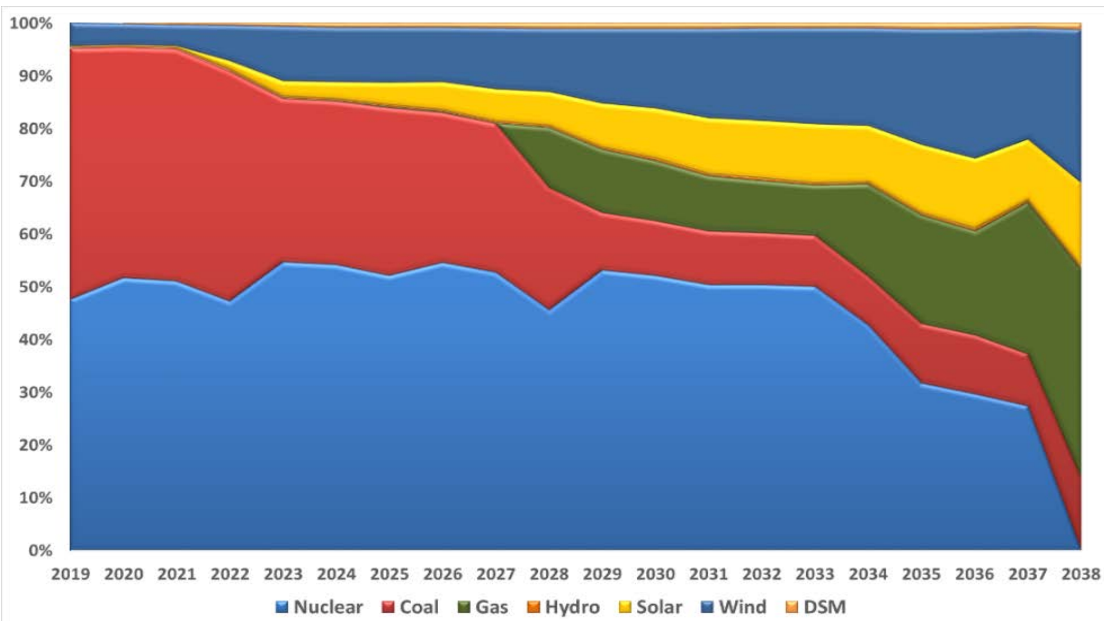

Figure ES- 4. I&M's Preferred Plan Percentage of Annual Energy by Supply Type (%)

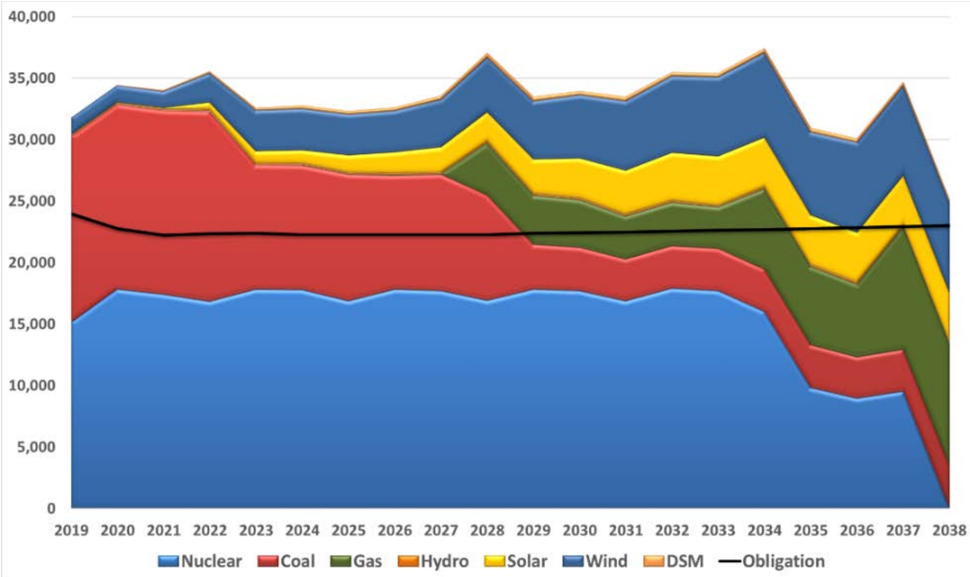

Figure ES- 5. I&M's Preferred Plan Annual Energy Position (GWh)

Figure ES- 6 provides insight to the emissions reductions over the planning period for the Preferred Plan. The Preferred Plan results in reductions from 2019 levels (baseline) of 65% for CO_2, and over 90% for NOx and SO_2 emissions by 2038.

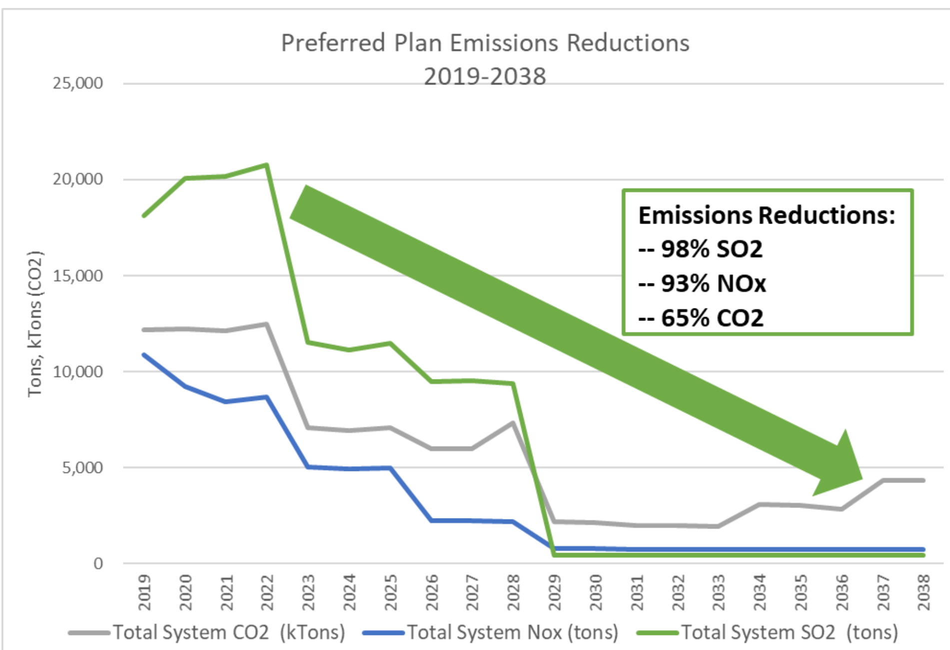

Figure ES- 6. Preferred Plan Emissions Reductions

Conclusion

The Preferred Plan provides reliable utility service over the 20-year planning period at reasonable cost, through a combination of renewable supply-side resources and demand-side programs in the near term and renewable and gas-fired resources in the long-term. The plan provides a roadmap for I&M to serve its customers' peak load and energy requirements throughout the 20-year planning period. The Preferred Plan includes incremental resources that will provide—in addition to the needed capacity to achieve mandatory PJM peak demand requirements—additional carbon-free energy to reduce the long-term exposure of the Company's customers to PJM energy markets and potential carbon emission restrictions.

The resource portfolios developed herein reflect, largely, assumptions that are subject to change; as an IRP is simply a snapshot of the future at a given time. As noted previously, this IRP is not a commitment to specific resource additions or other courses of action. The resource planning process continues to be complex, especially with regard to such things as technology advancement, changing energy supply pricing fundamentals, uncertainty of demand, and end-use efficiency improvements. These complexities exacerbate the need for flexibility and adaptability in any ongoing planning activity and resource planning process.

To that end, I&M intends to pursue the following short-term action plan:

1. Continue the evaluation of the Company's options related to Rockport operations.
2. Continue the evaluation of the integration of battery and micro-grid technology.
3. Continue the planning and regulatory actions necessary to implement additional economic EE programs in Indiana and Michigan.
4. Continue to monitor market prices for renewable resources, particularly wind and solar, and if economically advantageous, pursue competitive solicitations that would include self-build or acquisition options.
5. Monitor the status of, and participate in formulating any proposed carbon emissions regulations. Assess the implications of such regulations on I&M's resource profile.
6. Be in a position to adjust this action plan and future IRPs to reflect changing circumstances.

1.0 Introduction

1.1 Overview

This Report presents the 2018-19 Integrated Resource Plan (IRP or Plan) for Indiana Michigan Power Company (I&M or Company) including descriptions of assumptions, study parameters, and methodologies. The results integrate supply- and demand-side resources.

*The goal of the IRP process is to develop an indicative plan identifying the **amount**, **timing** and **type** of resources required to supply capacity and energy as part of its obligation to ensure a reliable and economical power supply to its Indiana and Michigan customers.*

In addition to developing a long-term plan for achieving reliability/reserve margin requirements as set forth by PJM and meeting I&M's obligation to ensure reliable and economical power supply to its customers, resource planning also impacts I&M's capital expenditure requirements, regulatory planning, environmental compliance, and other planning processes.

1.2 Introduction to I&M

I&M's customers consist of both retail and sales-for-resale (wholesale) customers located in the states of Indiana, and Michigan (see Figure 1). Currently, I&M serves approximately 466,000 and 129,000 retail customers in the states of Indiana and 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 4,837MW, which occurred in July 2011; and the highest recorded winter peak was 3,952MW, which occurred in January 2015. The most recent (summer 2018 and winter 2018/19) actual I&M summer and winter peak demands were 4,369MW and 3,770MW, occurring on June 18, 2018 and January 30, 2019, respectively.

Figure 1. I&M Service Territory

1.3 Integrated Resource Plan (IRP) Process

This Report covers the processes, assumptions, results and recommendations required to develop the Company's IRP. It uses the best available information at the time of preparation, but changes that may affect its results can, and do, occur without notice. Therefore, this IRP is not a commitment to a specific course of action, and all the resource actions are subject to change.

I&M's IRP process includes the following components/steps:

- describes the Company, the resource planning process in general, and the implications of current issues as they relate to resource planning;
- provides projected growth in demand and energy which serves as a key input into the Plan;
- identifies and evaluates demand-side options such as Energy Efficiency (EE) measures, Demand Response (DR) and Distributed Generation (DG);
- identify current supply resources, including projected changes to those resources (*e.g.,* de-rates or retirements), and transmission system integration issues;
- identifies and evaluates supply-side resource options;
- describes how the IRP ties to underlying PJM reserve margin requirements;
- solicit input from stakeholders regarding assumptions and analyses to be performed;
- perform resource modeling and use the results to develop portfolios;
- perform sensitivity analyses and risk analysis and use the results to determine the Company's Preferred Portfolio; and
- present the draft findings and recommendations to stakeholders, receive and consider their input, then develop the final Preferred Plan, and near term action plan.

1.3.1 I&M Stakeholder Process

I&M implemented an enhanced stakeholder outreach/public advisory process to guide the development of its Integrated Resource Plan. I&M designed and implemented the IRP public advisory process in accordance with the requirements of Commission Rule 170 IAC 4-7-2.6. I&M's goal throughout the process was to improve its resource planning process by conducting a meaningful, transparent and comprehensive stakeholder outreach effort to explore a wide-range of assumptions and resource options as I&M anticipates substantial changes in its resource mix over the IRP planning period. The result of this process is a well-reasoned, vetted Preferred Plan, based on current assumptions, to help guide I&M's future resource decisions.

I&M initiated its IRP stakeholder outreach efforts on January 15, 2018 by giving notice of the opportunity for public participation in the IRP development. I&M provided electronic notice and invitations to participate in the stakeholder process to the Commission staff, the Indiana Office of Utility Consumer Counselor, the interveners in I&M's most recent general rate case in Indiana, and stakeholders that participated in I&M's 2015 IRP public advisory process. I&M also provided invitations to its thirty largest commercial and industrial consumers. I&M established an IRP webpage on its website to allow customers, stakeholders, and interested persons to participate or follow the IRP public advisory process. The IRP webpage provided stakeholders with the 2015 IRP, 2018 registration information, "IRP 101" training materials and other IRP related information. This information can be found on the Company's IRP webpage at:https://www.indianamichiganpower.com/info/projects/IntegratedResourcePlan/. The following is a summary of the major activities.

Various stakeholders, including Indiana Utility Regulatory Commission (IURC, or "Commission") staff, Michigan Public Service Commission staff (MPSC staff), OUCC, Indiana Coal Council, CAC of Indiana, Sierra Club, individual I&M customers, public officials from the cities of Ft. Wayne and South Bend, representatives from colleges and universities and many other stakeholders participated throughout the process.

The foundation of the process was built upon four stakeholder meetings, with the majority held in I&M's service territory. The meetings brought interested stakeholders together with I&M's management and IRP teams to discuss the IRP planning process, exchange ideas, collect input, define assumptions, develop scenarios, review preliminary results, discuss risk and uncertainty associated with resource options and ultimately discuss I&M's Preferred Plan. Between stakeholder meetings, other stakeholder outreach activities occurred throughout the process, ranging from "breakout type" teleconference discussions with individual or groups of stakeholders on special topics of interest to customized training sessions on the use of the Plexos modeling tool. Please refer to Table 1 for a list of some of the stakeholder outreach activities.

A high level of professionalism and quality information exchanges occurred throughout the stakeholder outreach process. Although I&M considered all stakeholder input, a consensus on every input or assumption was not always achieved despite the best intentions of all parties. However, I&M believes the outreach process used to develop the IRP was an improvement over the process used in the development of its previous 2015 IRP filing. As a result, I&M's IRP represents credible and transparent efforts by all involved parties and provides a meaningful roadmap to inform and guide future resource decisions. Please refer to the IRP webpage for documentation summarizing the discussions and I&M's responses to stakeholder input. Some key take-aways from the process are summarized below and further discussed in Sections 4 and 5:

- Evaluating a “High Renewables” scenario;
- Evaluating Rockport scenarios with and without carbon futures;
- Evaluating an “EE Decrement” approach;
- Modifying EE potential to reflect the Market Potential Study;
- Evaluating unconstrained renewable build scenarios;
- Evaluating portfolios with Low Load with Low Band pricing and the High Load with High Band pricing;
- Providing access to the Company’s modeling software and associated training; and
- Providing opportunities at all Stakeholder meetings for stakeholders to present and discuss key issues, including a presentation by students from Ball State University Immersive Learning Project.

During the process, I&M sought and was granted three schedule extensions. The first extension request, made on July 26, 2018, extended the filing deadline from November 1, 2018 to February 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 January 8, 2018 Supplemental Motion prospering the Fifth Modification of Consent Decree ("Motion"). The Rockport Plant - a two-unit, 2600 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 October 26, 2018, extended the filing deadline from February 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.

Key dates related to the IRP public advisory process are shown below in Table 1.

Table 1 - Key IRP Public Advisory Process Dates

EVENT	DATE
I&M Issues Invitation to Participate in the IRP Stakeholder Process	January 15, 2018
I&M's IRP webpage operable for stakeholder input	January 15, 2018
Stakeholder Meeting #1	February 15, 2018
Stakeholder Meeting #2	April 11, 2018
I&M issues DSM Status Report	May 18, 2018
I&M Issues IRP Plan Key Inputs & Portfolios Update	December 10, 2018
Stakeholder comments due on portfolios, cost and performance attributes, scenarios and risk considerations	January 4, 2019
Stakeholder Meeting #3	February 21, 2019
Stakeholder Meeting #4	May 23, 2019

The presentation materials and meeting summaries from each stakeholder meeting were maintained throughout the process and can be found on I&M's IRP webpage.

2.0 Load Forecast and Forecasting Methodology

2.1 Summary of I&M Load Forecast

The I&M load forecast was developed by AEP's Economic Forecasting organization and completed in June 2019.[2] The final load forecast is the culmination of a series of underlying forecasts that build on each other. In other words, the economic forecast provided by Moody's Analytics is used to develop the customer forecast which is then used to develop the sales forecast which is ultimately used to develop the peak load and internal energy requirements forecast.

Over the next 20 year period (2019-2038)[3], I&M's service territory is expected to see population and non-farm employment growth of 0.0% and 0.3% 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 0.1% per year with stronger growth expected from the industrial class (+0.4% per year) while the residential class remains relatively flat and the commercial class experiences a decline (-0.3% per year) over the forecast horizon. Finally, I&M's internal energy and peak demand are expected to decrease at an average rate of 0.2% and 0.2% per year, respectively, through 2038.

2.2 Forecast Assumptions

2.2.1 Economic Assumptions

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.

[2] The load forecasts (as well as the historical loads) presented in this report 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 service by the utility. Such load serves as the starting point for the load forecasts used for generation planning. Internal load is a subset of connected load, which also includes directly connected load for which the utility serves only as a transmission provider. Connected load serves as the starting point for the load forecasts used for transmission planning.

[3] 20 year period begins with 2019, which is 3 months actual and 9 months forecasts.

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 the I&M service area.

2.2.2 Price Assumptions

The Company utilizes an internally developed service area electricity price forecast. This forecast incorporates information from the Company's financial plan for the near term and the U.S. Department of Energy (DOE) Energy Information Administration (EIA) outlook for the East North Central Census Region for the longer term. These price forecasts are incorporated into the Company's energy sales models, where appropriate.

2.2.3 Specific Large Customer Assumptions

I&M's customer service engineers are in frequent touch with industrial and commercial customers about their needs and activities. From these discussions, expected load additions or deletions are relayed to the Company.

2.2.4 Weather Assumptions

Where appropriate, the Company includes weather as an explanatory variable in its energy sales models. These models reflect historical weather for the model estimation period and normal weather for the forecast period.

2.2.5 Energy Efficiency (EE) and Demand Side Management (DSM) Assumptions

The Company's long term load forecast models account for trends in EE both in the historical data as well as the forecasted trends in appliance saturations as the result of various legislated appliance efficiency standards (Energy Policy Act of 2005 [EPAct], Energy Independence and Security Act [EISA] of 2007, etc.) modeled by the EIA. In addition to general trends in appliance efficiencies, the Company also administers multiple Demand-Side

Management (DSM) programs that the Commissions approve as part of its DSM portfolio. The load forecast utilizes the most current DSM programs, which either have been previously approved by or are pending currently before the Commission; at the time the load forecast is created to adjust the forecast for the impact of these programs. For this IRP, DSM programs through 2019 have been embedded into the load forecast.

2.3 Overview of Forecast Methodology

I&M's load forecasts are based mostly on econometric, statistically adjusted end-use and analyses of time-series data. This is helpful when analyzing future scenarios and developing confidence bands in addition to objective model verification by using standard statistical criteria.

I&M utilizes two sets of econometric models: 1) a set of monthly short-term models which extends for approximately 24 months and 2) a set of monthly long-term models which extends for approximately 30 years. The forecast methodology leverages the relative analytical strengths of both the short- and long-term methods to produce a reasonable and reliable forecast that is used for various planning purposes.

For the first full year of the forecast, the forecast values are generally governed by the short-term models. The short-term models are regression models with time series errors which analyze the latest sales and weather data to better capture the monthly variation in energy sales for short-term applications like capital budgeting and resource allocation. While these models produce extremely accurate forecasts in the short run, without logical ties to economic factors, they are less capable of capturing structural trends in electricity consumption that are more important for longer-term resource planning applications.

The long-term models are econometric, and statistically adjusted end-use models which are specifically equipped to account for structural changes in the economy as well as changes in customer consumption due to increased energy efficiency. The long-term forecast models incorporate regional economic forecast data for income, employment, households, output, and population.

The short-term and long-term forecasts are then blended to ensure a smooth transition from the short-term to the long-term forecast horizon for each major revenue class. There are some instances when the short-term and long-term forecasts diverge, especially when the long-term models are incorporating a structural shift in the underlying economy that is expected to occur within the first 24 months of the forecast horizon. In these instances, professional judgment is used to ensure that the final forecast that will be used in the peak models is reasonable. The class level sales are then summed and adjusted for losses to produce monthly net internal energy sales for the system. The demand forecast model utilizes a series of algorithms to allocate the monthly net internal energy to hourly demand. The inputs into forecasting hourly demand are internal energy, weather, 24-hour load profiles and calendar information.

A flow chart depicting the sequence of models used in projecting I&M's electric load requirements as well as the major inputs and assumptions that are used in the development of the load forecast is shown in Figure 2.

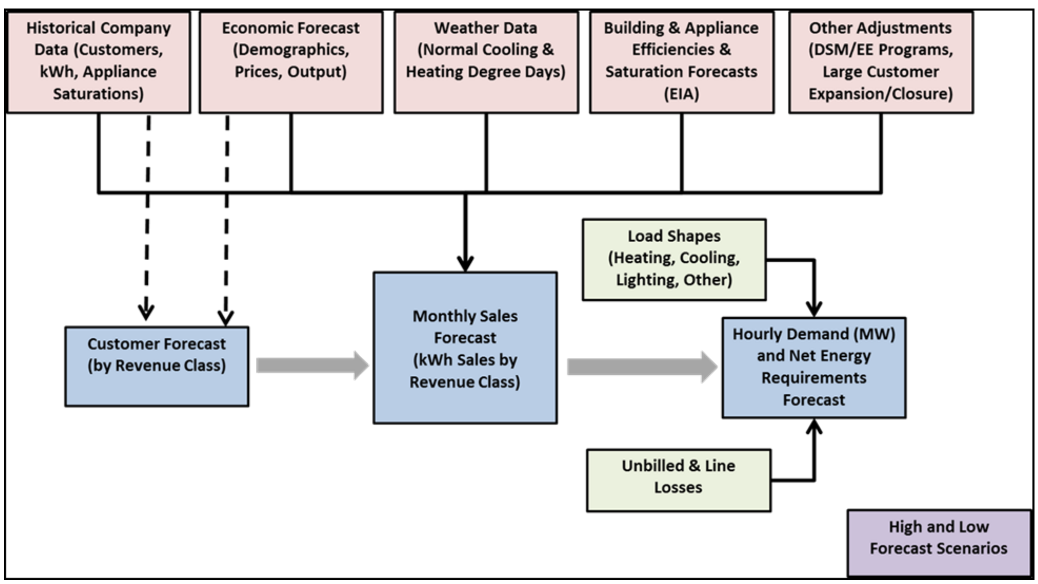

Figure 2. I&M Internal Energy Requirements and Peak Demand Forecasting Method

2.4 Detailed Explanation of Load Forecast

2.4.1 General

This section provides a more detailed description of the short-term and long-term models employed in producing the forecasts of I&M's energy consumption, by customer class. Conceptually, the difference between short- and long-term energy consumption relates to changes in the stock of electricity-using equipment and economic influences, rather than the passage of time. In the short term, electric energy consumption is considered to be a function of an essentially fixed stock of equipment. For residential and commercial customers, the most significant factor influencing the short term is weather. For industrial customers, economic forces that determine inventory levels and factory orders also influence short-term utilization rates. The short-term models recognize these relationships and use weather and recent load growth trends as the primary variables in forecasting monthly energy sales.

Over time, demographic and economic factors such as population, employment, income, and technology influence the nature of the stock of electricity-using equipment, both in size and composition. Long-term forecasting models recognize the importance of these variables and include all or most of them in the formulation of long-term energy forecasts.

2.4.2 Relative Energy Prices Impact on Electricity Consumption.

One important difference between the short-term and long-term forecasting models is their treatment of energy prices, which are only included in long-term forecasts. This approach makes sense because although consumers may suffer sticker shock from energy price fluctuations, there is little they can do to affect them in the short-term. They already own a refrigerator, furnace or industrial equipment that may not be the most energy-efficient model available. In the long term, however, these constraints are lessened as durable equipment is replaced and as price expectations come to fully reflect price changes.

2.4.3 Customer Forecast Models

The Company also utilizes both short-term and long-term models to develop the final customer count forecast. The short-term customer forecast models are time series models with intervention (when needed) using Autoregressive Integrated Moving Average (ARIMA) methods of estimation. These models typically extend for 24 months into the forecast horizon.

The long-term residential customer forecasting models are also monthly but extend for over 30 years. The explanatory jurisdictional economic and demographic variables may include gross regional product, employment, population, real personal income and households used in various combinations. In addition to the economic explanatory variables, the long-term customer models employ a lagged dependent variable to capture the adjustment of customer growth to changes in the economy. There are also binary variables to capture monthly variations in customers, unusual data points and special occurrences.

The short-term and long-term customer forecasts are blended as was described earlier to arrive at the final customer forecast that will be used as a primary input into both short-term and long-term usage forecast models.

2.4.4 Short-term Forecasting Models

The goal of I&M's short-term forecasting models is to produce an accurate load forecast for the first full year into the future. To that end, the short-term forecasting models generally employ a combination of monthly and seasonal binaries, time trends, and monthly heating cooling degree-days in their formulation. The heating and cooling degree-days are measured at weather stations in the Company's service area. The forecasts relied on ARIMA models.

The estimation period for the short-term models was January 2009 through January 2019. There are models for residential, commercial, industrial, other retail, and wholesale sectors. The industrial models are comprised of 20 (10 in each jurisdiction) large industrial models and models for the remainder of the industrial sector. The wholesale forecast is developed using models for Auburn, Indiana Michigan Municipal Distributors Association (IMMDA)-Indiana (which is comprised of Mishawaka, Bluffton, Garrett, Avilla, New Carlisle and Warren), Indiana Municipal Power Association, Wabash Valley Power Association, IMMDA-Michigan (which is comprised of Niles, South Haven and Paw Paw), Dowagiac and Sturgis.

Off-system sales and/or sales of opportunity are not relevant to the net energy requirements forecast as they are not requirements load or relevant to determining capacity and energy requirements in the IRP process.

2.4.5 Long-term Forecasting Models

The goal of the long-term forecasting models is to produce a reasonable load outlook for up to and beyond 30 years in the future. Given that goal, the long-term forecasting models employ a full range of structural economic and demographic variables, electricity and natural gas prices, weather as measured by annual heating and cooling degree-days, and binary variables to produce load forecasts conditioned on the outlook for the U.S. economy, for the I&M service-area economy, and for relative energy prices.

Most of the explanatory variables enter the long-term forecasting models in a straightforward, untransformed manner. In the case of energy prices, however, it is assumed, consistent with economic theory, that the consumption of electricity responds to changes in the price of electricity or substitute fuels with a lag, rather than instantaneously. This lag occurs for reasons having to do with the technical feasibility of quickly changing the level of electricity use even after its relative price has changed, or with the widely accepted belief that consumers make their consumption decisions on the basis of expected prices, which may be perceived as functions of both past and current prices.

There are several techniques, including the use of lagged price or a moving average of price that can be used to introduce the concept of lagged response to price change into an econometric model. Each of these techniques incorporates price information from previous periods to estimate demand in the current period.

The general estimation period for the long-term load forecasting models was 1995-2018 The long-term energy sales forecast is developed by blending of the short-term forecast with the long-term forecast. The energy sales forecast is developed by making a billed/unbilled adjustment to derive billed and accrued values, which are consistent with monthly generation.

2.4.5.1 Supporting Model

In order to produce forecasts of certain independent variables used in the internal energy requirements forecasting models, several supporting models are used, including natural gas price models for I&M's Indiana and Michigan service areas. These models are discussed below.

2.4.5.1.1 Consumed Natural Gas Pricing Model

The forecast price of natural gas used in the Company's energy models comes from a model of state natural gas prices for three primary consuming sectors: residential, commercial, and industrial. In the state natural gas price models, sectoral prices are related to East North Central Census region's sectorial prices, with the forecast being obtained from EIA's "2019 Annual Energy Outlook." The natural gas price model is based upon 1980-2018 historical data.

2.4.5.1.2 Residential Energy Sales

Residential energy sales for I&M are forecasted using two models, the first of which projects the number of residential customers, and the second of which projects kWh usage per customer. The residential energy sales forecast is calculated as the product of the corresponding customer and usage forecasts.

The residential usage model is estimated using a Statistically Adjusted End-Use model (SAE), which was developed by Itron, a consulting firm with expertise in energy modeling. This model assumes that use will fall into one of three categories: heat, cool, and other. The SAE model constructs variables to be used in an econometric equation where residential usage is a function of Xheat, Xcool, and Xother variables.

The Xheat variable is derived by multiplying a heating index variable by a heating use variable. The heating index incorporates information about heating equipment saturation; heating equipment efficiency standards and trends; and thermal integrity and size of homes. The heating use variable is derived from information related to billing days, heating degree-days, household size, personal income, gas prices, and electricity prices.

The Xcool variable is derived by multiplying a cooling index variable by a cooling use variable. The cooling index incorporates information about cooling equipment saturation; cooling equipment efficiency standards and trends; and thermal integrity and size of homes. The cooling use variable is derived from information related to billing days, heating degree-days, household size, personal income, gas prices and electricity prices.

The Xother variable estimates the non-weather sensitive sales and is similar to the Xheat and Xcool variables. This variable incorporates information on appliance and equipment saturation levels; average number of days in the billing cycle each month; average household size; real personal income; gas prices and electricity prices.

The appliance saturations are based on historical trends from I&M’s residential customer survey. The saturation forecasts are based on EIA forecasts and analysis by Itron. The efficiency trends are based on DOE forecasts and Itron analysis. The thermal integrity and size of homes are for the East North Central Census Region and are based on DOE and Itron data.

The number of billing days is from internal data. Economic and demographic forecasts are from Moody's Analytics and the electricity price forecast is developed internally.

The SAE residential model is estimated using linear regression models. These monthly models are typically for the period January 1995 through January 2019. It is important to note, as will be discussed later, that this modeling *has* incorporated the reductive effects of the EPAct, EISA, American Recovery and Reinvestment Act of 2009 (ARRA) and Energy Improvement and Extension Act of 2008 (EIEA2008) on the residential (and commercial) energy usage based on analysis by the EIA regarding appliance efficiency trends.

The long-term residential energy sales forecast is derived by multiplying the "blended" customer forecast by the usage forecast from the SAE model.

Separate residential SAE models are estimated for the Company's Indiana and Michigan jurisdictions.

2.4.5.2 Commercial Energy Sales

Long-term commercial energy sales are forecast using SAE models. These models are similar to the residential SAE models. These models utilize efficiencies, square footage and equipment saturations for the East North Central Region, along with electric prices, economic drivers from Moody's Analytics, heating and cooling degree-days, and billing cycle days. As with the residential models, there are Xheat, Xcool and Xother variables derived within the model framework. The commercial SAE models are estimated similarly to the residential SAE models.

2.4.5.3 Industrial Energy Sales

The Company uses some combination of the following economic and pricing explanatory variables: service area gross regional product manufacturing, service area manufacturing employment, FRB industrial production indexes, and service area industrial electricity prices. In addition, binary variables for months and special occurrences are incorporated into the models. Based on information from customer service engineers, there may be load added or subtracted from the model results to reflect plant openings, closures or load adjustments. Separate models are estimated for the Company's Indiana and Michigan jurisdictions. The last actual data point for the industrial energy sales models is January 2019.

2.4.5.4 All Other Energy Sales

The forecast of public-street and highway lighting relates energy sales to either service area employment or service area population and binary variables.

Wholesale energy sales are modeled relating energy sales to economic variables such as service area gross regional product, industrial production indexes, energy prices, heating and cooling degree-days and binary variables. Binary variables are necessary to account for discrete changes in energy sales that result from events such as the addition or deletion of new customers.

2.4.6 Internal Energy Forecast

2.4.6.1 Blending Short and Long-Term Sales

Forecast values for 2019 and 2020 are taken from the short-term process. Forecast values for 2021 are obtained by blending the results from the short-term and long-term models. 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. The goal of the blending process is to leverage the relative strengths of the short-term and long-term models to produce the most reliable forecast possible. However, at times the short-term models may not capture structural changes in the economy as well as the long-term models, which may result in the long-term forecast being used for the entire forecast horizon.

2.4.6.2 Large Customer Changes

The Company's customer service engineers are in continual contact with the Company's large commercial and industrial customers about their needs for electric service. These customers relay information about load additions and reductions. This information will be compared with the load forecast to determine if the industrial or commercial models are adequately reflecting these changes. If the changes are different from the model results, then add factors may be used to reflect those large changes that are different from those from the forecast models' output.

2.4.6.3 Losses and Unaccounted-For Energy

Energy is lost in the transmission and distribution of the product. This loss of energy from the source of production to consumption at the premise is measured as the average ratio of all Federal Energy Regulatory Commission (FERC) revenue class energy sales measured at the premise meter to the net internal energy requirements metered at the source. In modeling, Company loss study results are applied to the final blended sales forecast by revenue class and summed to arrive at the final internal energy requirements forecast.

2.4.7 Forecast Methodology for Seasonal Peak Internal Demand

The demand forecast model is 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.

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.

In the end, 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 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).

2.5 Load Forecast Results and Issues

All tables referenced in this section can be found in the Appendix of this Report in Exhibit A. The load forecast includes the forecast impact of customers opting for alternative generation suppliers. This is consistent with the Company's requirement to include such customers' load in its capacity planning in PJM.

2.5.1 Load Forecast

Exhibit A-1 presents I&M's annual internal energy requirements, disaggregated by major category (residential, commercial, industrial, other internal sales and losses) on an actual basis for the years 2009-2018, 2019 data are three months actual and nine months forecast and on a forecast basis for the years 2020-2038. The exhibit also shows annual growth rates for both the historical and forecast periods. Corresponding information for the Company's Indiana and Michigan service areas are given in Exhibits A-2A and A-2B. Figure 3 provides a graphical depiction of weather normal and forecast Company residential, commercial and industrial sales for 2002 through 2038.

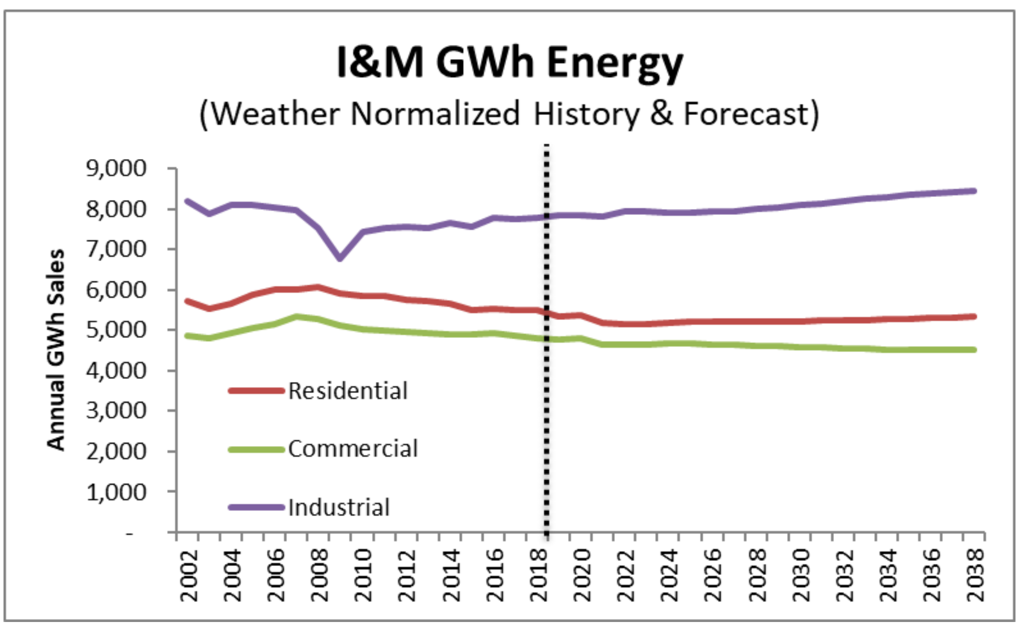

Figure 3. I&M GWh Retail Sales

2.5.2 Peak Demand and Load Factor

Exhibit A-3 provides I&M's seasonal peak demands, annual peak demand, internal energy requirements and annual load factor on an actual basis for the years 2009-2018, 2019 data are three months actual and nine months forecast and on a forecast basis for the year 2020-2038. The table also shows annual growth rates for both the historical and forecast periods.

Figure 4 presents actual, weather normal and forecast I&M peak demand for the period 2000 through 2038. Figure 4 depicts the Company's annual peak demand, which occurs in the summer season.

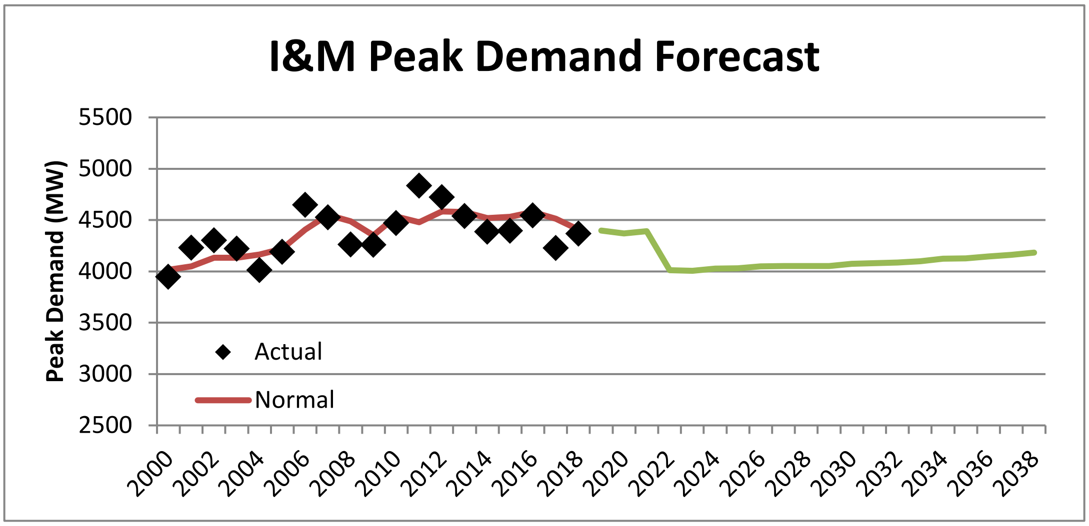

Figure 4. I&M Peak Demand Forecast

2.5.3 Performance of Past Forecasts

The performance of the Company's past load forecasts is reflected in Exhibit A-5, which displays, in graphical form, annual internal energy requirements and summer peak demands experienced since 1990, along with the corresponding forecasts made in 2007, 2009, 2011, 2013, 2015 and 2019 (the current forecast). This exhibit reflects the uncertainty inherent in the forecasting process, and demonstrates the changing perceptions of the future.

2.5.4 Historical and Projected Load Profiles

Exhibits A-6 through A-9 display various historical and forecasted load profiles pertinent to the planning process. Exhibit A-6 shows profiles of monthly peak internal demands for I&M on an actual basis for the years 2008, 2013 and 2018, and as forecasted for 2028 and 2038. Exhibit A-7 shows, for the winter-peak month and summer-peak month for the years 2013 and 2018, respectively, I&M's average daily internal load shape for each day of the week, along with the peak-day load shape. Exhibit A-8 displays, for the forecast years 2019 and 2039, I&M'se daily internal load shapes for a simulated week in the winter-peak month (January) and summer-peak month (August). In both cases, a weekday is assumed to represent the day of the monthly (and seasonal) peak. Such load shapes were developed for use in integrated resource planning analyses.

The Company maintains an on-going load research program consisting of samples of each major rate class in each jurisdiction. Exhibit A-9 displays I&M's Indiana jurisdiction residential, commercial and industrial customer class summer and winter 2018 load shape information derived from these samples.

2.5.5 Weather Normalization

The load forecast presented in this report assumes normal weather. To the extent that weather is included as an explanatory variable in various short- and long-term models, the weather drivers are assumed to be normal for the forecast period.

Exhibit A-10 compares the recorded (i.e., actual) and weather-normalized summer and winter peak internal demands and annual internal energy requirements for I&M for the last ten years, 2009-2018.

Peak normalization is a fundamental process of evaluating annual or monthly peaks over time, without the impact of "abnormal" weather events and load curtailment events. The limited number of true annual or monthly peaks over time makes it difficult to use traditional regression analysis. So a regression model is used to determine statistical relationships among a set of daily observations that are similar to annual/monthly peaks and weather conditions. Any load curtailment or significant outage events are added back to the daily observations. The peak normalization demand model is replicated numerous times in a Monte Carlo (stochastic) simulation model. This approach derives probability distributions for both the dependent variable (peak) and independent variables (weather). Multiple estimates for peak are obtained over time that ultimately produces a weather normalized peak.

Similarly, for each year, the weather-normalized internal energy requirements were determined by applying, to each month of the year, an adjustment related to heating or cooling degree-days, as appropriate, to each sector of the recorded internal energy requirements. The adjustment for each sector was obtained as the product of (1) the difference between the service area's expected (or "normal") heating or cooling-degree-days for the month and the actual heating or cooling degree-days for that month and (2) a weather-sensitivity factor (in MWh per heating or cooling degree-day), which was estimated by regressing over the past years monthly sectoral energy requirements against heating or cooling degree-days for the month. The normalized monthly energy requirements thus determined for each sector were then added for all sectors across all twelve months to obtain the net total weather-normalized energy requirements for the year.

2.5.6 Data Sources

The data used in developing the I&M load forecast come from both internal and external sources. The external sources are varied and include state and federal agencies, as well as Moody's Analytics. Exhibit A-11 identifies the data series and associated sources, along with notes on adjustments made to the data before incorporation into the load forecast.

2.6 Load Forecast Trends & Issues

2.6.1 Changing Usage Patterns

Over the past decade, there has been a significant change in the trend for electricity usage from prior decades. Figure 5 presents I&M's historical and forecasted residential and commercial usage per customer between 1991 and 2025. During the first decade shown (1991-2000), residential usage per customer grew at an average rate of 0.5% per year, while the commercial usage grew by 0.6% per year. Over the next decade (2001-2010), growth in residential usage growth was at 0.5% per year while the commercial class usage decreased by 0.6% per year. In the last decade shown (2011-2020) residential usage is projected to decline at a rate of 1.4% per year while the commercial usage decreases by an average of 1.0% per year. It is worth noting that the decline in residential and commercial usage accelerated between 2008 and 2018, with usage declining at average annual rates of 1.1% and 1.2% for residential and commercial sectors, respectively, over that period. For the forecast period 2020 through 2025, residential and commercial usage per customer are project to decline at average annual rates of 0.4% and 0.3%, respectively.

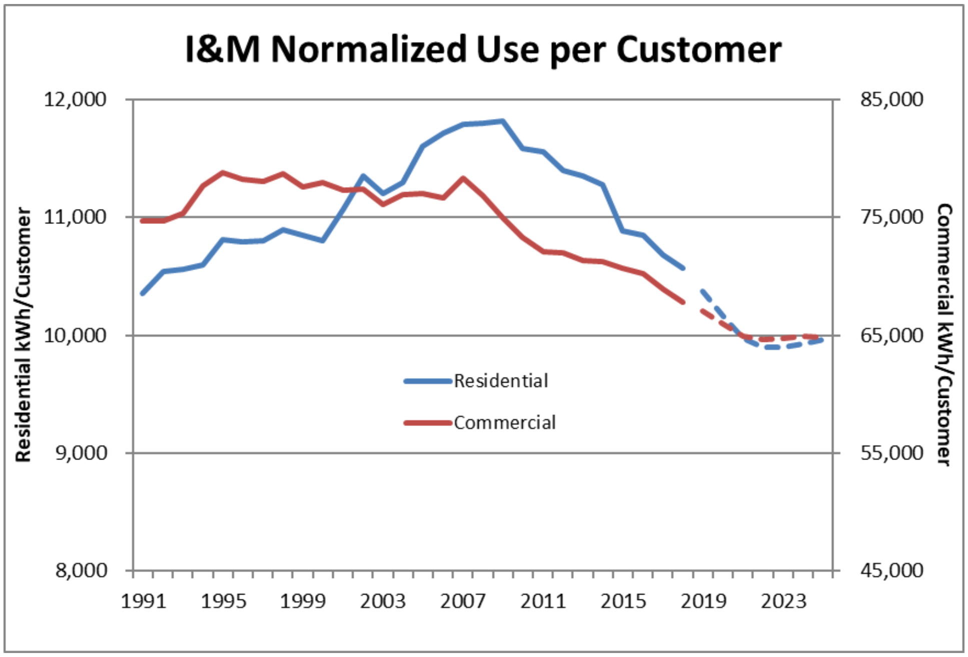

Figure 5. I&M Normalized Use per Customer (kWh)

The SAE models are designed to account for changes in the saturations and efficiencies of the various end-use appliances. Every 3-4 years, the Company conducts a Residential Appliance Saturation Survey to monitor the saturation and age of the various appliances in the residential home. This information is then matched up with the saturation and efficiency projections from the EIA which includes the projected impacts from various enacted federal policies mentioned earlier.

The result of this is a base load forecast that already includes some significant reductions in usage as a result of projected EE. For example, Figure 6 shows the assumed cooling efficiencies embedded in the statistically adjusted end-use models for cooling loads. It shows that the average Seasonal Energy Efficiency Ratio (SEER) for central air conditioning is projected to increase from 11.5 in 2010 to nearly 13.6 by 2030. The chart shows a similar trend in projected cooling efficiencies for heat pump cooling as well as room air conditioning units.

Figure 7 shows similar improvements in the efficiencies of lighting and clothes washers over the same period.

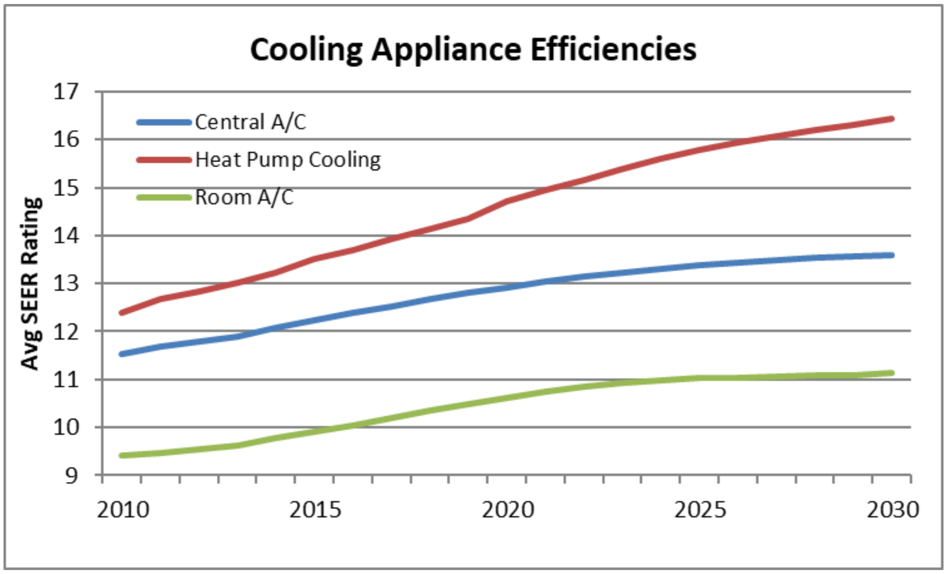

Figure 6. Projected Changes in Cooling Efficiencies, 2010-2030

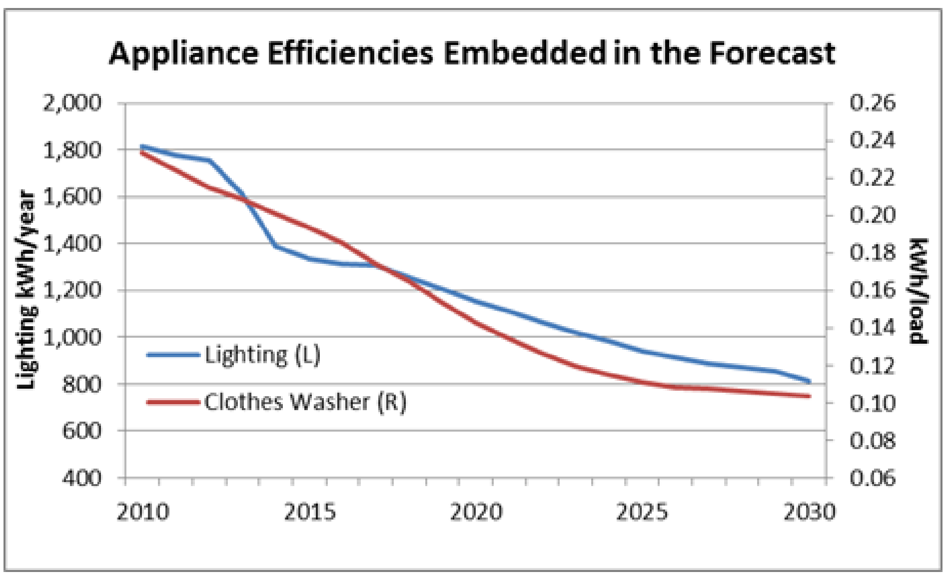

Figure 7. Projected Changes in Lighting & Clothes Washer Efficiencies, 2010-2030

Figure 8 shows the impact of appliance, equipment and lighting efficiencies on the Company's weather normal residential usage per customer. This graph provides weather normalized residential energy per customer and an estimate of the effects of efficiencies on usage. In addition, historical and forecast I&M residential customers are provided.

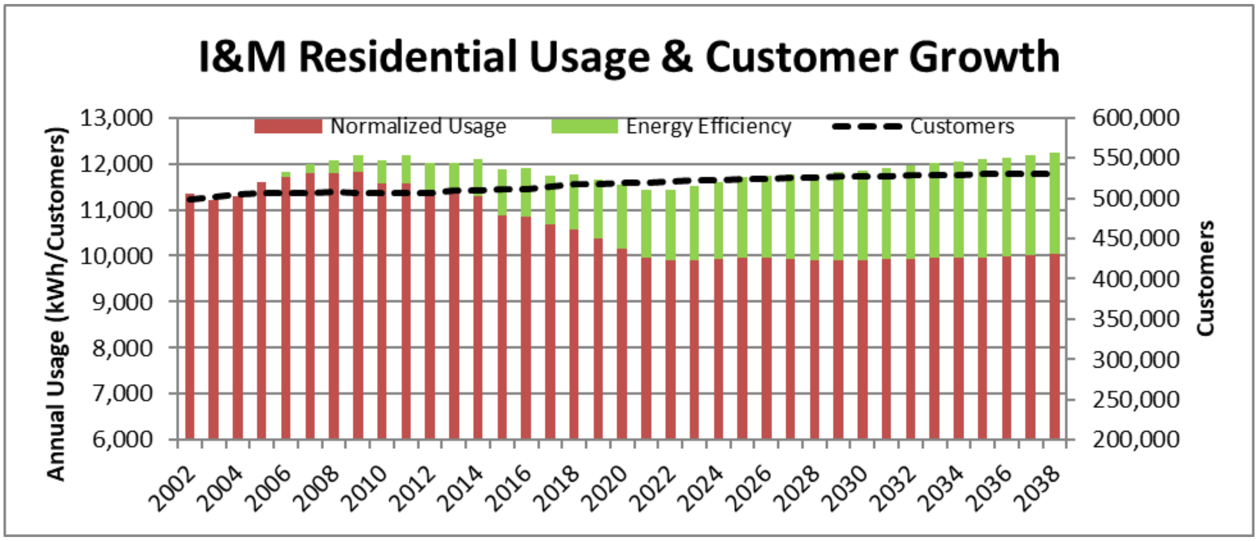

Figure 8. Residential Usage & Customer Growth

2.6.2 Demand-Side Management (DSM) Impacts on the Load Forecast

The end-use load forecasting models account for changing trends and saturations of energy efficient technologies throughout the forecast horizon. However, the Company is also actively engaged in administering various commission approved DSM and EE programs which would further accelerate the adoption of energy efficient technology within its service territory. As a result, the base load forecast is adjusted to account for the impact of these programs that is not already embedded in the forecast.

For the near term horizon (through 2019), the load forecast uses assumptions from the DSM programs currently approved. For the years beyond 2019, the IRP model selected optimal levels of economic EE, which may differ from the levels currently being implemented, based on projections of future market conditions. The initial base load forecast accounts for the evolution of market and industry efficiency standards. As a result, energy savings for a specific EE program are degraded over the expected life of the program. Exhibit A-17 details the impacts of the approved EE programs included in the load forecast, which represent the cumulative degraded value of EE program impacts throughout the forecast period. The IRP process then adds the selected optimal economic EE, resulting in the total IRP EE program savings.

Exhibit A-12 provides the DSM/EE impacts incorporated in I&M's load forecast provided in this Report. Annual energy and seasonal peak demand impacts are provided for the Company and its Indiana and Michigan jurisdictions.

2.6.3 Interruptible Load

The Company has two customers with interruptible provisions in their contracts. These customers have interruptible contract capacity of 15MW. However, these customers are expected to have 14MW and 14MW available for interruption at the time of the winter and summer peaks, respectively. An additional 139 customers have 280MW available for interruption in emergency situations in DR agreements. The load forecast does not reflect any load reductions for these customers. Rather, the interruptible load is seen as a resource when the Company's load is peaking. As such, estimates for DR resource impacts are reflected by I&M in determination of PJM-required resource adequacy (i.e., I&M's projected capacity position).

2.6.4 Blended Load Forecast

As noted above, at times the short-term models may not capture structural changes in the economy as well as the long-term models, which may result in the long-term forecast being used for the entire forecast horizon. Exhibit A-13 provides an indication of which retail models are blended and which strictly use the long-term model results. In addition, all of the wholesale forecasts utilize the long-term model results.

In general, forecast values for the years 2019 and 2020 were typically taken from the short-term process. Forecast values for 2021 are obtained by blending the results from the short-term and long-term models. 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 of 2021 the entire forecast is from the long-term models. This blending allows for a smooth transition between the two separate processes, minimizing the impact of any differences in the results. Figure 9 illustrates a hypothetical example of the blending process (details of this illustration are shown in Exhibit A-14). However, in the final review of the blended forecast, there may be instances where the short-term and long-term forecasts diverge especially when the long-term forecast incorporates a structural shift in the economy that is not included in the short-term models. In these instances, professional judgment is used to develop the most reasonable forecast.

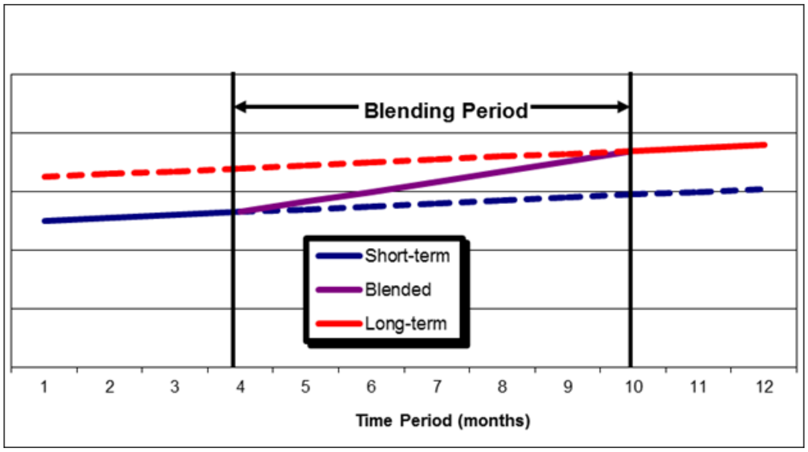

Figure 9. Load Forecast Blending Illustration

2.6.5 Large Customer Changes

The Company's customer service engineers are in continual contact with the Company's large commercial and industrial customers about their needs for electric service. These customers will relay information about load additions and reductions. This information will be compared with the load forecast to determine if the industrial or commercial models are adequately reflecting these changes. If the changes are different from the model results, then additional factors may be used to reflect those large changes that differ from the forecast models' output.

2.6.6 Wholesale Customer Contracts

Company representatives are in continual contact with wholesale customer representatives about their contractual needs. The forecast included in this IRP is reduced to reflect the expiration of a number of wholesale contracts.

2.7 Load Forecast Model Documentation

Displays of model equations, including the results of various statistical tests, along with data sets, are provided in the Exhibits H, K, L and M of the Appendix.

2.8 Changes in Forecasting Methodology

Opportunities to enhance forecasting methods are explored by I&M and AEP on a continuing basis. The forecasts reported herein reflect a limited number of changes in the methodology implemented during the last four years. One significant change from the Company's 2015 IRP is that the high-low economic growth model is now developed for I&M and each operating company separately. Previously, AEP East was modeled for high-low scenarios and it was assumed all companies would have the same forecast spread.

2.9 Load-Related Customer Surveys

A residential customer survey was last conducted in the fall of 2018 in which data on end-use appliance penetration and end-use saturation rates were obtained. Beginning in 1980, in intervals of approximately three years, the Company has regularly surveyed residential customers to monitor customers' demographic characteristics, appliance ownership, penetration of new energy use products and services, and conservation efforts.

The Company has no proposed schedule for industrial and/or commercial customer surveys to obtain end-use information in the near future. I&M monitors its industrial and commercial (and residential) customer end-use consumption patterns through its ongoing load research program.

2.10 Load Research Class Interval Usage Estimation Methodology

AEP is a participating member of the Association of Edison Illuminating Companies (AEIC) Load Research Committee, was a significant contributor to the AEIC Load Research Manual, and uses the procedures set forth in that manual as a guide for load research practices. AEP maintains an on-going load research program in each retail rate jurisdiction which enables class hourly usage estimates to be derived from actually metered period data for each rate class for each hour of each day. The use of actual period metered data results in the effective capture of weather events and economic factors in the representation of historical usage.

For each rate class in which customer maximum demand is normally less than 1MW, a statistical random sample is designed and selected to provide at least 10%

precision at the 90% confidence level at times of company monthly peak demand. In the sample design process, billing usage for each customer in the class is utilized in conjunction with any available class interval data to determine the optimal stratified sample design using the Dalenius-Hodges stratification procedure. Neyman Allocation is used to determine the necessary number of sample customers in each stratum. All active customers with the requisite data available in the rate class population are included in the sample selection process, which uses a random systematic process to select primary sample points and backup sample points for each primary point.

For selected sample sites that reside within an Advanced Metering Infrastructure (AMI) area, the interval data is extracted from the Meter Data Management System (MDM) and stored in Hadoop or imported into the ITRON MV90 System. For selected sample sites that reside outside of an AMI area, each location undergoes field review and subsequent installation of an interval data recorder. The recorder is normally set to record usage in fifteen minute intervals. For rate classes in which customer maximum demand is normally 1MW or greater, each customer in the class is interval metered, and these are referred to as 100% sampled classes. The interval data is retrieved at least monthly, validated through use of the ITRON MV90 System or the MDM, edited or estimated as necessary, and stored for analytical purposes. The status of each sample point undergoes on-going review and backup sample points replace primary sample points as facilities close, change significant parameters such as rate class, or become unable to provide required information due to safety considerations. This on-going sample maintenance process ensures reasonable sample results are continuously available, and samples are periodically refreshed through a completely new sample design and selection process to capture new building stock and when necessary to capture rate class structure changes.

Prior to analysis, as an additional verification that all interval data is correct, interval data for each customer is summed on a billing month basis and the resulting total energy and maximum demand are compared to billing quantities. Any significant discrepancies between the interval data and the billing quantities are further investigated and corrected, as needed. Rate class analysis is then performed through the Load Research Analysis System. The sample interval data is post-stratified and weighted to represent the sampled class populations, and total class hourly load estimates are developed. The analysis provides hourly load estimates at both the stratum and class levels, and standard summary statistics, including non-coincident peaks, coincident peaks, coincidence factors, and load factors, at the class, stratum, and sample point levels.

The resulting class hourly load estimates are examined through various graphical approaches, the summary statistics are reviewed for consistency across time, and the monthly sample class energy results are compared against billed and booked billed and accrued values. Any anomalies are investigated, and a rate class analysis may be re-worked if the investigation shows that is necessary. When analysis and review of all rate classes is completed, losses are applied to the hourly rate class estimates, the class values are aggregated, and the resulting total estimate is compared to the company hourly load derived from the system interchange and generation metering. Any significant differences between the customer level load research derived numbers and the system level numbers are investigated, and class results may be re-analyzed, if necessary.

Rate classes are often comprised of combinations of commercial and industrial customers. Separate commercial and industrial hourly load estimates are developed after rate class analysis is completed. Monthly billing usage for each commercial and industrial customer is acquired from the customer information system and is imported into the Load Research Analysis System, along with the sample point interval data available from the rate class random and 100% samples. The sample interval data is post-stratified and weighted to represent the commercial and industrial class populations, and total class hourly load estimates are developed. Losses are then applied to the resulting commercial and industrial class estimates, the values are combined with the residential class hourly load estimates from the rate class analysis, the class values are aggregated, and the resulting total estimate is compared to the company hourly load derived from the system interchange and generation metering. Any significant differences between the load research derived numbers and the system level numbers are investigated, and class results may be re-analyzed, if necessary. Final residential, commercial, and industrial class hourly load estimates are provided to the forecasting organization for use in the long-term forecasting and planning process.

2.11 Customer Self-Generation

I&M customers that install renewable energy resource self-generation facilities are typically served through either I&M's Net Metering Service Rider (Rider NMS) or Cogeneration and/or Small Production Service (Tariff COGEN/SPP). Through December 31, 2018, 471 customers have installed net metering and or co-generation qualifying customer-generation facilities which are interconnected and/or net metered with a total nameplate capacity of approximately 13MW.

However, customer self-generation (net metering and co-generation) historically has been minimal in the I&M service territory. For a variety of reasons, including the relatively low retail cost of electricity, I&M's customers generally have not found self-generation to be cost effective. Thus, the load forecast does not include significant increases to customer self-generation.

However, as discussed in Section 4.7.5.1, the costs of customer owned generation is declining and may decline to the point where customers begin to adopt these technologies in significant numbers. This IRP addresses this possibility through modeling customer owned generation as a resource, since this potential is not included as part of the load forecast. Future IRPs may include the impacts of customer owned generation in the load forecast, as acceptance becomes better understood and levels more predictable.

2.12 Load Forecast Scenarios

The base case load forecast is the expected path for load growth that the Company uses for planning. There are a number of known and unknown potentials that could drive load growth different from the base case. While potential scenarios could be quantified at varying levels of assumptions and preciseness, the Company has chosen to frame the possible outcomes around the base case. The Company recognizes the potential desire for a more exact quantification of outcomes, but the reality is if all possible outcomes were known with a degree of certainty, then they would become part of the base case.

Forecast sensitivity scenarios have been established which are tied to respective high and low economic growth cases. The high and low economic growth scenarios are consistent with scenarios laid out in the EIA's 2019 Annual Outlook. While other factors may affect load growth, this analysis only considered high and low economic growth. The economy is seen as a crucial factor affecting future load growth.

The low-case, base-case and high-case forecasts of summer and winter peak demands and total internal energy requirements for I&M are tabulated in Exhibit A-15.

For I&M, the low-case and high-case energy and peak demand forecasts for the last forecast year, 2038, represent deviations of about 12.4% below and 12.0% above, respectively, the base-case forecast.

During the load forecasting process, the Company developed various other scenarios. Figure 10 provides a graphical depiction of the scenarios developed in conjunction with the load provided in this report.

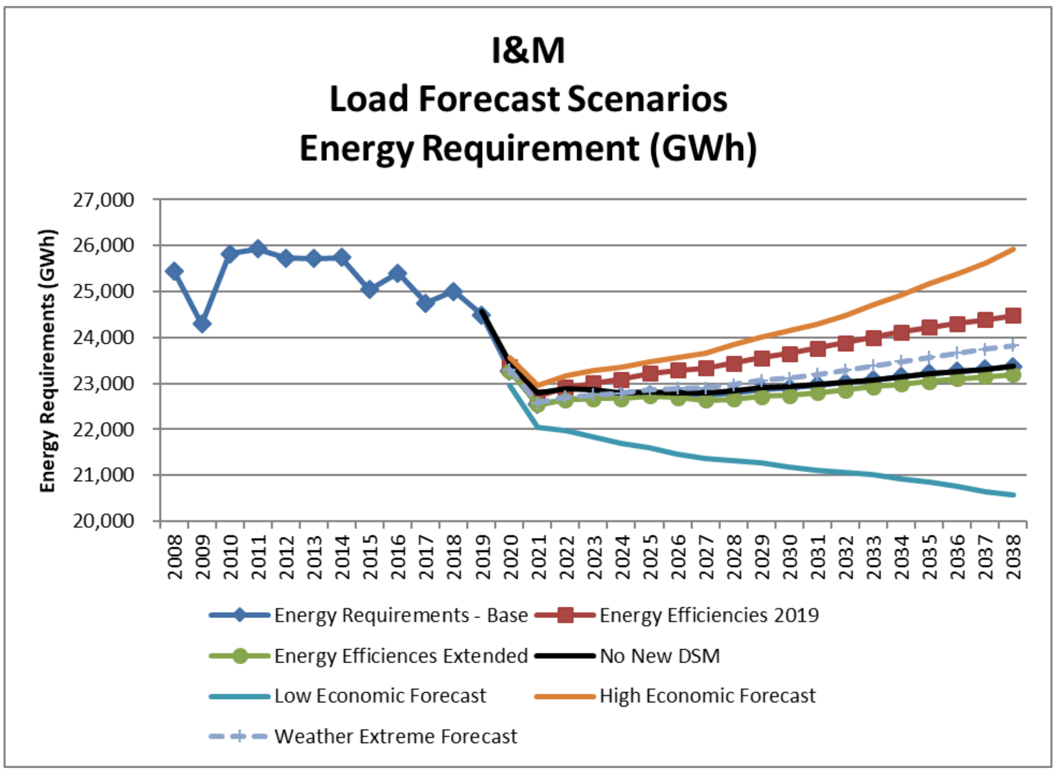

Figure 10. Load Forecast Scenarios

The no new DSM scenario extracts the DSM included in the load forecast and provides what load would be without the increased DSM activity. The energy efficiencies 2019 scenario keeps energy efficiencies at 2019 levels for the residential and commercial equipment. Both of these scenarios result in a load forecast greater than the base forecast.

The energy efficiencies extended scenario has energy efficiencies developing at a faster pace than is represented in the base forecast. This scenario is based on analysis developed by the Energy Information Administration. This forecast is lower than the base forecast due to enhanced energy efficiency for residential and commercial equipment.

The weather extreme forecast assumes increased average daily temperatures for both the winter and summer seasons which results in diminished heating degree-days in the winter and increased cooling degree days in the summer. This analysis is based on a potential impact of climate change developed by Purdue University. The extreme weather scenario was developed in response to inquiries in one of the Company's stakeholder meetings. This scenario results in increased load in the summer and diminished load in the winter, with the net result being a higher energy requirements forecast. Exhibit A-16 provides graphical displays of the range of forecasts of summer and winter peak demand for I&M along with the impacts of the weather scenario for each season.

All of these alternative scenarios fall within the boundary of the Company's high and low economic scenario forecasts. The Company's expectations are that any reasonable scenario developed will fall within this range of forecasts.

2.13 Other Considerations Based on Prior Feedback

A. High-Low Economic Scenarios

The Director's Final Report on 2015-16 IRPs (2015 Report) expressed concern of the Company relying on high-low scenario model for the AEP East rather than a company specific model. In this IRP, I&M has developed a company specific high-low economic growth model. The Company believes that this type of modeling enhances the understanding of potential variation in load.

B. Large Customer Load Addition

Feedback was provided about the use of large customer changes as add factors to the load forecast. The Company continues to use add factors as post model adjustments to the load forecast. These may be in terms of load additions or reductions. With regards to load additions, the Company will take into account normal load growth already accounted for in the model prior to including an add factor for load additions. Load reductions for plant closures or diminished load are typically taken as is, because these are perceived to be outside the modeling framework.

C. Forecast Blending

Comments were noted about the blending process and the Company often using the long-term forecast. The blending process is an integral part of the Company's forecast process. It entails not only evaluating the annual load growth, but also the monthly variation within each year's forecast. The Company's forecast process evaluates the pros and cons of both the short- and long-term forecasts before determining what they believe is the optimal forecast for the Company for each sector. While the Company has selected the long-term forecast in many instances, the forecast was enriched with the evaluation process and the consideration of the short-term forecast.

D. Customer Surveys

The 2015 Report inquired about customer surveys. The Company continues to do residential surveys every three years or so. The results from these surveys are used to enhance the Company's residential energy forecasts. The Company does not and currently does not have plans to do surveys of commercial and industrial customers. These customers are much heterogeneous than the residential sector. The Company believes that the costs of these surveys would outweigh the benefits derived from them.

E. Advanced Metering Infrastructure (AMI)

The 2015 Report also discussed the importance of AMI to enhancing the load forecast. AMI remains relatively in its infancy in the I&M service territory. The Company has proposed to have it deployed through 2022. As the Company gets access to more of this type of data, it will become an integral part of the load forecasting process. This information will enhance the Company's understanding of the load and enhance the load forecast.

3.0 Resource Evaluation

3.1 Current Resources

An initial step in the IRP process is the demonstration of the capacity resource requirements. This aspect of the traditional "needs" assessment must consider projections of:

- existing capacity resources—current levels and anticipated changes;
- anticipated changes in capability due to efficiency and/or environmental considerations;
- changes resulting from decisions surrounding unit disposition evaluations;
- regional and sub-regional capacity and transmission constraints/limitations;
- load and peak demand;
- current DR/EE; and
- PJM capacity reserve margin and reliability criteria.

3.2 Existing Generating Resources and PJM Capacity Planning Requirements

I&M operates is the PJM Interconnection, L.L.C. (PJM) and in ReliabilityFirst Corporation, a Regional Entity of the North American Electric Reliability Corporation (NERC). I&M participates in the PJM energy market. Based on offers placed into this market, the PJM Zone's generation resources are economically dispatched for energy to serve the entire PJM load, including I&M's internal load. Separately, PJM has a mandatory capacity market. PJM allows an entity to either participate in a capacity auction (in which PJM functions to procure the capacity) or utilize the Fixed Resource Requirement (FRR) option in which the entity supplies its own capacity resource either through constructing the necessary capacity or through bilateral contracts with existing resources. PJM requires all FRR entities to make mandatory commitments to meet their capacity reserve requirements by supplying PJM with an FRR plan three years in advance of the delivery year. The same three year forward concept holds for entities using the RPM auction process. The Reliability Assurance Agreement (RAA) sets forth the rules of participation in the PJM Capacity Market and also establishes capacity obligations of PJM Load Serving Entities (LSEs).

Currently, I&M, along with other subsidiaries of AEP, collectively participate as a PJM FRR entity and is committed to the FRR option for PJM through PJM Planning Year (PY) 2021/22. FRR election decisions and FRR Plans for PJM PY 2022/23 are due to PJM later this year. The underlying minimum reserve margin criterion to be utilized in the determination of I&M's capacity need is based on the PJM Installed Reserve Margin (IRM) of 16.0 percent.[4] The ultimate reserve margin is determined from the PJM Forecast Pool Requirement (FPR), which considers the IRM and PJM's Pool-Wide Average Equivalent Demand Forced Outage Rate ($EFOR_D$).[5] The PJM FPR is 8.95% for the 2019/2020 PJM planning year, and decreases to 8.87% for the remainder of the planning period, which ends with the 2038/2039 PJM planning year.

Table 2 identifies the current generating resources included in the Company's plan. Future plans surrounding these assets must take into account each unit's useful service life. Unit retirements are incorporated in I&M's plans based upon each unit's in-service date along with the anticipated service life. Retirement dates are periodically reviewed and adjusted with respect to a unit's ability to maintain safe, reliable, and economic operation, as well as external factors such as environmental regulations.

[4] Per Section 2.1.1 of PJM Manual 18: PJM Capacity Market (Effective: Jan 1, 2019). PJM Planning Parameters are updated each year prior to the upcoming Base Residual Auction. These values can be obtained from http://pjm.com/markets-and-operations/rpm.aspx. This IRP uses the PJM Planning Parameters , which reflect PJM's Capacity Performance proposal, as currently interpreted by I&M.

[5] Per Section 2.1.4 of PJM Manual 18: PJM Capacity Market (Effective: Jan 1, 2019).

$FPR = (1 + IRM) * (1 – EFOR_D)$. Reserve Margin = FPR – 1.

Table 2. I&M Generation Assets as of December 2018

Unit Name	Location	Fuel Type	C.O.D. [1]	PJM Installed Capacity (MW) [2]	PJM Unforced Capacity (MW)	
Cook 1	Bridgman, MI	Nuclear	1975	1,006	994	
Cook 2	Bridgman, MI	Nuclear	1978	1,148	1,120	
Rockport 1	Rockport, IN	Coal	1984	1,118	1,024	
Rockport 2	Rockport, IN	Coal	1989	1,105	1,064	
Berrien Springs 1-12	Berrien Springs, MI	Water	1908	6	5	
Buchanan 1-10	Buchanan, MI	Water	1919	3	2	
Constantine 1-4	Constantine, MI	Water	1921	1	1	
Elkhart 1-3	Elkhart, IN	Water	1913	3	3	
Mottville 1-4	White Pigeon, MI	Water	1923	2	1	
Twin Branch 1-8	Mishawaka, IN	Water	1904	4	4	
Fowler Ridge 1	Benton County, IN	Wind	2008	100	11	(B)
Fowler Ridge 2	Benton County, IN	Wind	2009	50	7	(B)
Headwaters	Randolph County, IN	Wind	2014	200	26	(B)
Wildcat	Madison County, IN	Wind	2014	100	13	(B)
Deer Creek	Grant County, IN	Solar	2015	3	1	
Olive	St. Joseph County, IN	Solar	2016	5	3	
Twin Branch Solar	St. Joseph County, IN	Solar	2016	3	1	
Watervliet	Berrien County, MI	Solar	2016	5	2	
Clifty Creek 1-6	Madison, IN	Coal	1956	96	90	(A)
Kyger Creek 1-5	Cheshire, OH	Coal	1955	79	75	(A)
				5,034	4,448	

(1) Commercial operation date.
(2) Peak net capability as of filing.
(A) Represents I&M's share of these units
(B) Represents capacity from Power Purchase Agreements (PPAs)

Figure 11 below depicts I&M's current generation resources, their nameplate ratings and current age.

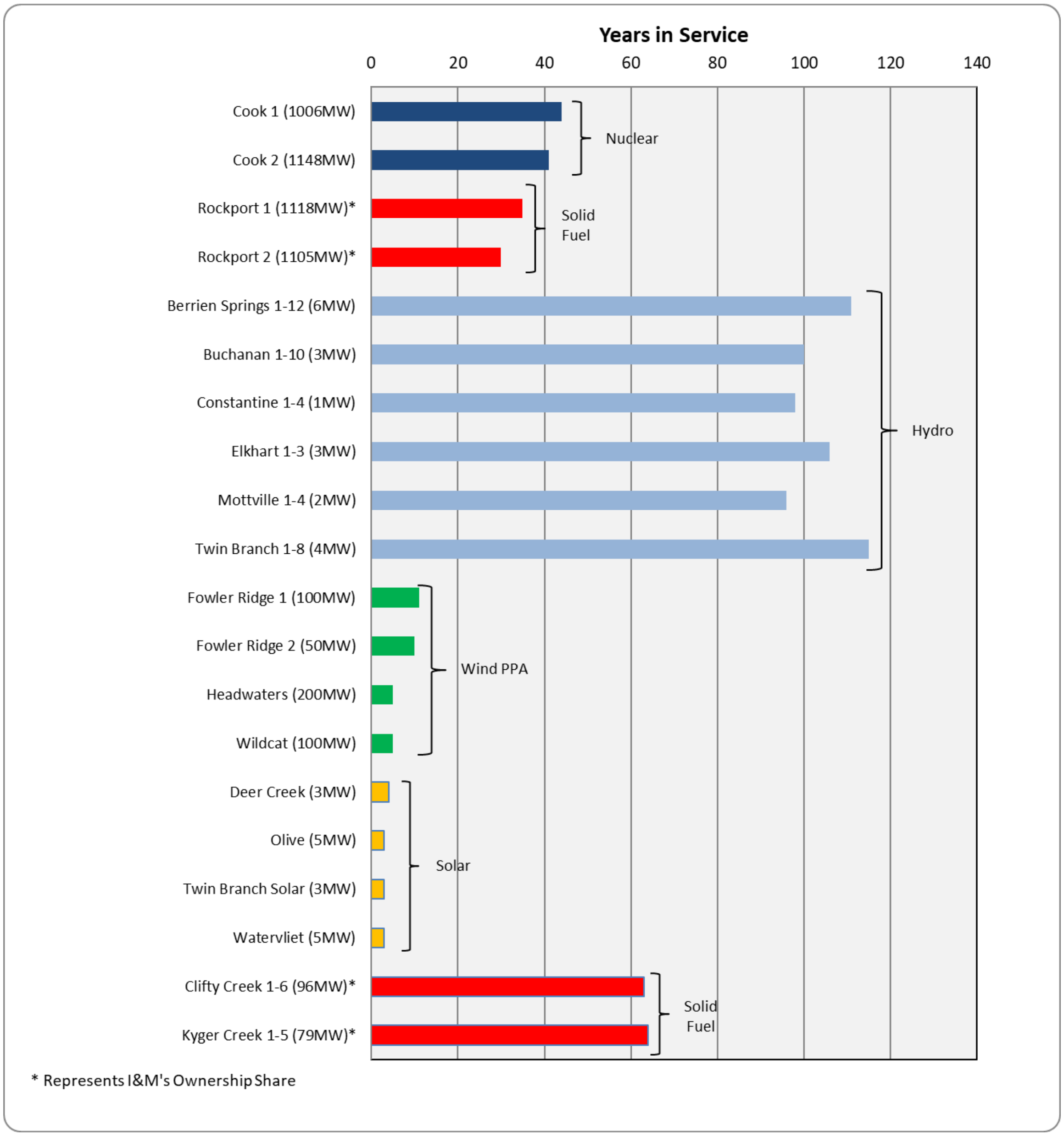

Figure 11 Current Resource Fleet (Owned & Contracted) with years in Service, as of April 1, 2019

I&M currently utilizes several capacity entitlements to meet the minimum PJM reserve margin requirement, including generation from Company owned assets, joint ventures, and hydro and wind Power Purchase Agreements (PPAs). The "Going-In" position includes planned solar additions of 20MW, 24MW and 20MW (nameplate) in 2021, 2022 and 2023, respectively.

3.2.1 PJM Capacity Performance Rule Implications

On June 9, 2015 FERC issued an order largely accepting PJM's proposal to establish a new "Capacity Performance" product. The resulting PJM rule requires future capacity auctions to transition from current or "Base" capacity products to Capacity Performance products. Capacity Performance resources will be held to stricter requirements than current Base resources and will be assessed heavy penalties for failing to deliver energy when called upon. The rulemaking is effective with the 2020/2021 PJM planning year.

For this IRP, the Company assumes it will continue as a Fixed Resource Requirement (FRR) entity within the PJM Capacity planning process which I&M has now notified PJM it will do. The Company also assumes, consistent with the Capacity Performance rule, that unit capabilities will be based on the current Unforced Capacity (UCAP) definition, which is Installed Capacity (ICAP) times 1 minus EFORd or ICAP X (1 – EFORd).

3.2.2 Fuel Inventory and Procurement Practices - Coal

I&M plans to have adequate fuel supplies at its coal generating units to meet full-load burn requirements in both the short-term and the long-term. American Electric Power Service Corporation (AEPSC), acting as agent for I&M, is responsible for the procurement and delivery of coal to I&M's coal generating station, as well as establishing coal inventory target level ranges and managing those levels. AEPSC's primary objective is to assure the availability of an adequate, reliable supply of coal at the lowest reasonable delivered cost. Deliveries are arranged so that sufficient coal is available at all times. The consistency and quality of the coal delivered to the generating station is also vitally important. The consistency of the sulfur content of the delivered coal is fundamental to I&M's achievement and compliance with the applicable environmental limitations.

3.2.2.1 Specific Units

I&M has one coal-fired generating station in Indiana. The Rockport Generating Station, located in Spencer County, consists of two 1,300-megawatt coal fired generating units. Sulfur dioxide (SO_2) emissions at Rockport are limited to 1.2 lb. SO_2/MMBtu and, beginning in 2016, there is a SO_2 cap on emissions. Compliance with the emission limit is achieved by using a blend consisting primarily of low-sulfur bituminous and sub-bituminous coal. The coal supply for

Rockport currently uses a blend of sub-bituminous Powder River Basin (PRB) coal from Wyoming and low-sulfur bituminous coal from Central Appalachian basin and/or Colorado basin sources. In order to comply with stricter EPA emissions standards, Dry Sorbent Injection (DSI) technology is being used at both Rockport units. Rockport Unit 2's new DSI technology began operating in December 2014 and Rockport Unit 1's began operating in April 2015. The new DSI technology did not change the current coal blend at Rockport.

3.2.2.2 Procurement Process

Coal delivery requirements are determined by taking into account existing coal inventory, forecasted coal consumption, and adjustments for contingencies that necessitate an increase or decrease in coal inventory levels. I&M's total coal requirements are met using a portfolio of long-term arrangements and spot-market purchases that are primarily made through a competitive Request for Proposal process. Long-term contracts (>1 year) support a relatively stable and consistent supply of coal, but often do not provide the required flexibility to meet changes in demand for coal fired generation in a low gas price and/or low power demand scenario. Spot purchases are used to provide additional flexibility to accommodate changing demand. Occasionally, spot purchases may also be made to test-burn any promising and potential new sources of coal in order to determine their acceptability as a fuel source in a given power plant's generating units.

3.2.2.3 Contract Descriptions

Rockport's coal needs for 2019 are being supplied primarily through a long-term supply agreement with Peabody COALSALES, LLC. There are also long-term supply agreements with Blackhawk Coal Sales, LLC and Contura Coal Sales, LLC. Additionally, several committed spot contracts contribute to fulfilling the supply requirements. Any remaining supply requirements will be fulfilled with purchases that are not yet committed. As these agreements expire, additional coal supplies will be contracted to maintain a sufficient supply of coal.

3.2.2.4 Inventory

I&M coordinates to maintain an adequate coal supply to meet full-load burn requirements at the plant. However, in situations where coal supplies fall below prescribed minimum levels, programs have been developed to conserve coal supplies. In the event of a severe coal shortage, I&M would implement procedures for the orderly reduction of the consumption of electricity, in accordance with the Emergency Operating Plan.

3.2.2.5 Forecasted Fuel Prices

I&M specific forecasted annual fuel prices, by unit, for the period 2019 through 2048 are displayed in Exhibit J (Confidential) of the Appendix.

3.3 Environmental Issues and Implications

It should be noted that the following discussion of environmental regulations is based on the requirements currently in effect and those compliance options viewed as most likely to be implemented by the Company and incorporated into its analysis within this IRP. Activity including but not limited to Presidential Executive Orders, litigation, petitions for review, and Federal Environmental Protection Agency (EPA) proposals may delay the implementation of these rules, or alter the requirements set forth by these regulations. While such activities have the potential to materially change the compliance options available to the Company in the future, all potential outcomes cannot be reasonably foreseen or estimated and the assumptions made within the IRP represent the Company's best estimation of outcomes as of the filing date. The Company is committed to closely following developments related to environmental regulations, and will update its analysis of compliance options and timelines when sufficient information becomes available to make such judgments.

3.3.1 Clean Air Act Requirements

The Clean Air Act (CAA) establishes a comprehensive program to protect and improve the nation’s air quality and control sources of air emissions. The states implement and administer many of these programs and could impose additional or more stringent requirements. The primary regulatory programs that continue to drive investments in AEP’s existing generating units include: (a) periodic revisions to National Ambient Air Quality Standards (NAAQS) and the development of State Implementation Plans (SIPs) to achieve any more stringent standards, (b) implementation of the regional haze program by the states and the Federal EPA, (c) regulation of hazardous air pollutant emissions under MATS, (d) implementation and review of Cross-State

Air Pollution Rule (CSAPR), a FIP designed to eliminate significant contributions from sources in upwind states to non-attainment or maintenance areas in downwind states and (e) the Federal EPA's regulation of greenhouse gas emissions from fossil fueled electric generating units under Section 111 of the CAA.

Notable developments in significant CAA regulatory requirements affecting the Company's operations are discussed in the following sections.

3.3.2 National Ambient Air Quality Standards

The Federal EPA issued new, more stringent NAAQS for PM in 2012 and ozone in 2015; the existing standards for NO2 and SO2 were retained after review by the Federal EPA in 2018 and 2019, respectively. Implementation of these standards is underway.

In 2016, the Federal EPA completed an integrated review plan for the 2012 PM standard. Work is currently underway on scientific, risk and policy assessments necessary to develop a proposed rule, which is anticipated in 2021.

The Federal EPA finalized non-attainment designations for the 2015 ozone standard in 2018. The Federal EPA has confirmed that the CSAPR program satisfies all interstate transport obligations associated with the 2008 ozone standard, as all areas of the country are expected to attain the 2008 ozone standard before 2023, but that finding has been challenged in the U.S. Court of Appeals for the D.C. Circuit. Challenges to the 2015 ozone standard and Federal EPA's 2018 rule governing implementation of the 2015 ozone standard also are pending in the U.S. Court of Appeals for the District of Columbia Circuit.

3.3.3 Cross-State Air Pollution Rule (CSAPR)

In 2011, the Federal EPA issued CSAPR as a replacement for the Clean Air Interstate Rule, a regional trading program designed to address interstate transport of emissions that contributed significantly to downwind non-attainment with the 1997 ozone and PM NAAQS. CSAPR relies on SO2 and NOx allowances and individual state budgets to compel further emission reductions from electric utility generating units. Interstate trading of allowances is allowed on a restricted sub-regional basis.

Petitions to review the CSAPR were filed in the U.S. Court of Appeals for the District of Columbia Circuit. In 2015, the court found that the Federal EPA over-controlled the SO2 and/or NOx budgets of 14 states. The court remanded the rule to the Federal EPA for revision consistent with the court's opinion while CSAPR remained in place.

In 2016, the Federal EPA issued a final rule to address the remand and to incorporate additional changes necessary to address the 2008 ozone standard. The final rule significantly reduced ozone season budgets in many states and discounted the value of banked CSAPR ozone season allowances beginning with the 2017 ozone season. The rule has been challenged in the courts and petitions for administrative reconsideration have been filed I&M has been complying with the more stringent ozone season budgets while these petitions were pending.

3.3.1 Mercury and Other Hazardous Air Pollutants (HAPs) Regulation

In 2012, the Federal EPA issued a rule addressing a broad range of HAPs from coal and oil-fired power plants. The rule established unit-specific emission rates for units burning coal on a 30-day rolling average basis for mercury, PM (as a surrogate for particles of non-mercury metals) and hydrogen chloride (as a surrogate for acid gases). In addition, the rule proposed work practice standards, such as boiler tune-ups, for controlling emissions of organic HAPs and dioxin/furans. Compliance was required within three years. Management obtained administrative extensions for up to one year at several units to facilitate the installation of controls or to avoid a serious reliability problem.

In 2014, the U.S. Court of Appeals for the District of Columbia Circuit denied all of the petitions for review of the 2012 final rule. Industry trade groups and several states filed petitions for further review in the U.S. Supreme Court.

In 2015, the U.S. Supreme Court reversed the decision of the U.S. Court of Appeals for the District of Columbia Circuit. The court remanded the MATS rule to the Federal EPA to consider costs in determining whether to regulate emissions of HAPs from power plants. In 2016, the Federal EPA issued a supplemental finding concluding that, after considering the costs of compliance, it was appropriate and necessary to regulate HAP emissions from coal and oil-fired units. Petitions for review of the Federal EPA's determination were filed in the U.S. Court of Appeals for the District of Columbia Circuit. In 2018, the Federal EPA released a revised finding that the costs of reducing HAP emissions to the level in the current rule exceed the benefits of those HAP emission reductions. The Federal EPA also determined that there are no significant changes in control technologies and the remaining risks associated with HAP emissions do not justify any more stringent standards. Therefore, the Federal EPA proposed to retain the current MATS standards without change. A final rule has not yet been issued.

I&M's Rockport Plant is located in Rockport, Indiana and consists of two similar coal fired generating units fired with pulverized coal. Units 1 and 2 at the Rockport Plant were placed in service in 1984 and 1989, respectively, and have been efficient and reliable performers for I&M and its customers. For over thirty years, the Rockport Plant has been a cornerstone of I&M's generation fleet and has achieved low emission rates of nitrogen oxides (NOx) and SO2 by consuming predominantly low-sulfur coal from the Powder River Basin (PRB). Each unit is equipped with an Electrostatic Precipitator (ESP) for collection of particulate matter (PM, also referred to as fly ash); low-NOx burners (LNB) with overfire air (OFA) to minimize the formation of NOx during combustion; Activated Carbon Injection (ACI) for the capture of mercury emissions; and Dry Sorbent Injection (DSI) for the reduction of acid gases and sulfur dioxide (SO2) removal. In addition, Selective Catalytic Reduction (SCR) technology has been installed on Rockport Unit 1 and is currently under construction on Rockport Unit 2. These SCR installations will further reduce Rockport's NOx emissions.

Each unit at the Rockport Plant currently consumes a blend of approximately 87% PRB sub-bituminous coal and 13 percent eastern bituminous coal. This high percentage PRB blend results in lower emission rates of SO2 and NOx relative to burning 100 percent eastern bituminous coal.

3.3.2 Climate Change, CO_2 Regulation and Energy Policy

In 2015, the Federal EPA published the final CO2 emissions standards for new, modified and reconstructed fossil fuel-fired steam generating units and combustion turbines, and final guidelines for the development of state plans to regulate CO2 emissions from existing sources, known as the Clean Power Plan (CPP).

The final rules were challenged in the courts. In 2016, the U.S. Supreme Court issued a stay on the final CPP, including all of the deadlines for submission of initial or final state plans, until a final decision is issued by the U.S. Court of Appeals for the District of Columbia Circuit and the U.S. Supreme Court considers any petition for review. In 2017, the President issued an Executive Order directing the Federal EPA to reconsider the CPP and the associated standards for new sources. The Federal EPA filed a motion to hold the challenges to the CPP in abeyance, and the cases are still pending.

In 2018, the Federal EPA proposed the Affordable Clean Energy (ACE) rule to replace the CPP with new emission guidelines for regulating CO2 from existing sources. ACE would establish a framework for states to adopt standards of performance for utility boilers based on heat rate improvements for such boilers. In 2018, the Federal EPA filed a proposed rule revising the standards for new sources and determined that partial carbon capture and storage is not the best system of emission reduction because it is not available throughout the U.S. and is not cost-effective. I&M is actively monitoring these rulemaking activities.

For purposes of this Integrated Resource Plan, as described later, I&M conducts analyses around carbon regulation by evaluating scenarios with and without costs associated with potential future carbon regulations.

3.3.3 New Source Review (NSR) Settlement

On October 9, 2007, AEP's eastern companies entered into a consent decree with the Department of Justice to settle all complaints filed against AEP's affiliates, including I&M. Under the original Consent Decree I&M was required to retrofit SCR and FGD technology on Rockport Units 1 and 2 by December 31, 2017 and December 31, 2019, respectively.

On February 22, 2013, the parties filed a proposed Third Modification to the Consent Decree in the United States District Court for the Southern District of Ohio, Eastern Division. This modified Consent Decree authorized I&M to install dry sorbent injection (DSI) technology on both Rockport Units by April 16, 2015, and deferred the installation of higher efficiency FGD technology on these two units until December 31, 2025 and December 31, 2028. The installation of SCR technology on Rockport Units 1 and 2 by December 31, 2017 and December 31, 2019, respectively, is still required under the modified Consent Decree.

The modified Consent Decree also established annual tonnage limits for SO2 for the Rockport Plant. These annual station-wide caps are displayed in Table 3.

Table 3. Modified Consent Decree Annual SO_2 Cap for Rockport Plant

Calendar Year	Annual Tonnage Limitations for SO_2
2016	28,000
2017	28,000
2018	26,000
2019	26,000
2020-2025	22,000
2026-2028	18,000
2029, and each year thereafter	10,000

In 2019, the parties to the Consent Decree entered into a Fifth Joint Modification to authorize I&M to enhance the DSI systems and achieve the 10,000 ton per year cap on emissions at the Rockport Plant beginning in calendar year 2021. The parties also agreed to extend the date to complete the SCR installation at Rockport Unit 2 until June 1, 2020, to facilitate the DSI work to be completed during the same outage. Rockport Unit 1 will retire at the end of 2028, and the SO2 emissions cap at Rockport Plant will decline to 5,000 tons per year. The Rockport Units will also achieve a 30-day rolling average SO2 emissions rate of 0.15 lbs/mmBtu and a 30-day rolling average NOx emission rate of 0.090 lbs/mmBtu at the combined stack, beginning in calendar year 2021. These changes are currently out for public comments, and are expected to be finalized in the third quarter of 2019. The unit characteristics included in the Fifth Joint Modification are not included in the modeling results of this IRP, due to the recent nature of the pending agreement.

3.3.4 Coal Combustion Residual Rule

In 2015, the Federal EPA published a final rule to regulate the disposal and beneficial re-use of coal combustion residuals (CCR), including fly ash and bottom ash generated at coal-fired electric generating units and FGD gypsum generated at some coal-fired plants. The rule applies to new and existing CCR landfills and CCR surface impoundments at operating electric utility or independent power production facilities. The rule imposes construction and operating obligations, including location restrictions, liner criteria, structural integrity requirements for impoundments, operating criteria and additional groundwater monitoring requirements to be implemented on a schedule spanning an approximate four-year implementation period. In 2018, I&M's Rockport Plant was required to begin assessment-monitoring programs to determine if unacceptable groundwater impacts will trigger future corrective measures.

The final 2015 rule was challenged in the courts. In 2018, the U.S. Court of Appeals for the District of Columbia Circuit issued its decision vacating and remanding certain provisions of the 2015 rule. Remaining issues were dismissed. The provisions addressed by the court's decision, including changes to the provisions for unlined impoundments and legacy sites, will be the subject of further rulemaking consistent with the court's decision.

Prior to the court's decision, the Federal EPA issued a final rule in July 2018 that modifies certain compliance deadlines and other requirements in the rule. In December 2018, challengers filed a motion for partial stay or vacate of the July 2018 rule. On the same day, the Federal EPA filed a motion for partial remand of the July 2018 rule. The court granted Federal EPA's motion, and further rulemaking to address the court's decisions is expected to be completed near the end of 2019.

Other utilities and industrial sources have been engaged in litigation with environmental advocacy groups who claim that releases of contaminants from wells, CCR units, pipelines and other facilities to ground waters that have a hydrologic connection to a surface water body represent an "unpermitted discharge" under the Clean Water Act (CWA). Two cases have been accepted by the U.S. Supreme Court for further review of the scope of CWA jurisdiction. The Federal EPA has opened a rulemaking docket to solicit information to determine whether it should provide additional clarification of the scope of CWA permitting requirements for discharges to ground water. On April 23, 2019, Federal EPA issued an "Interpretative Statement" considering comments received in the rulemaking docket and determined that "releases to groundwater are excluded from the scope of the NPDES program, even where pollutants are conveyed to jurisdictional surface waters via groundwater." EPA will receive comments on the interpretive statement through June 7, 2019.

The necessary I&M Rockport Plant site-specific analyses to determine the requirements under the final CCR Rule are ongoing, but it is anticipated that plant modifications will be necessary. I&M's Rockport Plant is already equipped with a dry fly ash handling system and a dry ash landfill to meet current permit requirements positioning the plant favorably for future compliance. I&M is waiting on EPA to finalize both CCR and ELG rules to better understand our future compliance obligation.

3.3.5 Solid Waste Disposal

Prior to 2010, Rockport Plant fly ash was produced and marketed for reuse in applications that included flowable fill, ready mix concrete, raw feed for cement manufacture, and structural fills. Fly ash sales ceased beginning in 2010 because the Activated Carbon Injection system (ACI) to control mercury was placed into service. Fly ash is disposed of at the on-site landfill permitted by the Indiana Department of Environmental Management (IDEM). The landfill is underlain with clay and a geosynthetic plastic liner, has a groundwater monitoring well system that is sampled to monitor for potential impacts to groundwater, and storm-water runoff collection and treatment system, with discharge regulated by an IDEM-issued National Pollutant Discharge Elimination System (NPDES) permit. Unused bottom ash is stored in a pond for future use, which is also regulated by an IDEM NPDES permit.

On December 19, 2014 the US EPA signed the final Coal Combustion Residuals (CCR) Rule which became effective on October 19, 2015. This rule impacts the bottom ash pond and landfill at the Rockport Plant.

Non-hazardous solid wastes generated at Rockport Plant, as well as the hydro facilities, are disposed at permitted municipal solid waste landfills. Typical solid wastes may include general trash, non-hazardous solvents, and hydraulic fluid, which may be recycled or properly disposed of using licensed vendors. These facilities recycle numerous non-hazardous and hazardous wastes, including everything from paper and cardboard to batteries and used mercury.

3.3.6 Hazardous Waste Disposal

Rockport is typically a small-quantity generator of hazardous waste, such as parts washer by-products, batteries, light bulbs, and paints. The plant recycles light bulbs and batteries. Rockport has significantly reduced the amount of solvents generated in the parts washers by purchasing its own equipment and processing its own non-hazardous solvents.

3.3.7 Clean Water Act Regulations

In 2014, the Federal EPA issued a final rule setting forth standards for existing power plants that is intended to reduce mortality of aquatic organisms pinned against a plant's cooling water intake screen (impingement) or entrained in the cooling water. The rule was upheld on review by the U.S. Court of Appeals for the Second Circuit. Compliance timeframes are established by the permit agency through each facility's National Pollutant Discharge Elimination System permit as those permits are renewed. IDEM determined during the 2015 permit renewal at Rockport Plant that the Best Technology Available (BTA) is the existing cooling water intake structures. Therefore, no modifications are required. Cook Nuclear Plant's renewal application, including the required 316(b) information, is currently being reviewed by the Michigan Department of Environmental Quality (MDEQ).

In 2015, the Federal EPA issued a final rule revising effluent limitation guidelines for electricity generating facilities. The rule established limits on FGD wastewater, fly ash and bottom ash transport water and flue gas mercury control wastewater to be imposed as soon as possible after November 2018 and no later than December 2023. The rule was challenged in the U.S. Court of Appeals for the Fifth Circuit. In April 2019, the court vacated and remanded to the Federal EPA the portions of the rule dealing with legacy wastewater and leachate for reconsideration consistent with the decision. A final rule revising the compliance deadlines for FGD wastewater and bottom ash transport water to be no earlier than 2020 was issued in September 2017, and has been challenged in the courts. EPA is reconsidering the final standards for FGD wastewater and bottom ash transport water, and a proposed rule could be issued later in 2019. To ensure compliance with the ELG Rule, I&M has determined that wastewater treatment projects may be necessary at the Rockport Plant and these have been considered as part of the respective long-term unit evaluations. The Rockport Plant utilizes a wet bottom ash handling system and a dry fly ash handling system. Cook Nuclear Plant is unaffected by these rule revisions.

In 2015, the Federal EPA and the U.S. Army Corps of Engineers jointly issued a final rule to clarify the scope of the regulatory definition of "waters of the United States" in light of recent U.S. Supreme Court cases. The final rule was challenged in several courts that have reached different conclusions about whether the 2015 rule should be implemented. In December 2018, the Federal EPA and the U.S. Army Corps of Engineers released a proposed rule revising the definition, which would replace the definition in the 2015 rule and could significantly alter the scope of certain CWA programs. A final rule is expected during 2019.

3.4 I&M Current Demand-Side Programs

3.4.1 Background

DSM refers to, for the purposes of this IRP, utility programs, including tariffs, which encourage reduced energy consumption, either at times of peak consumption or throughout the day/year. 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. As will be discussed later, within the IRP process, the potential for additional or "incremental" demand-side resources, including EE activity—over and above the levels embedded in the load forecast—as well as other grid related projects such as Volt VAR Optimization (VVO), are modeled on the same economic basis as supply-side resources. However, because customer-based EE programs are limited by factors such as customer acceptance and saturation, an estimate as to their costs, timing and maximum impacts must be formulated. For the year 2019, the Company anticipates 290MW of peak DSM reduction (total company basis); consisting of 18MW and 272MW of "passive" EE and "active" DR activity, respectively.[6]

[6] "Passive" demand reductions are achieved via "around-the-clock" *EE* program activity as well as voluntary price response programs; "Active" DR is centered on summer peak reduction initiatives, including interruptible contracts, tariffs, and direct load control programs.

3.4.2 Existing Demand Response (DR)/Energy Efficiency (EE) Mandates and Goals

The EISA legislation requires, among other things, a phase-in of heightened lighting efficiency standards, appliance standards, and building codes and a back-stop provision effective in 2020 that prohibits the sale of light bulbs having an efficacy of less than 45 lumens per watt. Moreover, the cost of LED light bulbs has dropped dramatically as well. The impact of the phase-in requirements, back-stop provision, and market changes will have a pronounced effect on energy consumption as explained in Section 2.6. Many of the standards already in place impact lighting. For instance, since 2013, 2014, and 2015 common residential incandescent and compact fluorescent lighting alternatives have been phased out and less efficient commercial lighting fixtures requiring the use of magnetic and electronic ballasts have been replaced with highly efficient LED fixtures. Given that "lighting" measures have comprised a large portion of utility-sponsored EE programs prior to the phase-out, this pre-established transition is already incorporated into the SAE long-term load forecast modeling previously described in Section 2.4.5 and will likely greatly affect the market potential of utility EE programs in the near and intermediate term. Table 4 and Table 5 depict the current schedule for the implementation of new EISA codes and standards.

Table 4. Forecasted View of Relevant Residential Energy Efficiency Code

Technology	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Chillers	2007 ASHRAE 90.1										
Roof Top Units	EER 11.0/11.2										
PTAC	EER 11.7		EER 11.9								
Heat Pump	EER 11.0/COP 3.3										
PTHP	EER 11.9/COP 3.3										
Ventilation	Constant Air Volume/Variable Air Volume										
Screw-in/Pin Lamps	Advanced Incandescent (20					Advanced Incandescent (45 lumens/watt)					
Linear Fluorescent	T8 (89 lumens/watt)			T8 (92.5 lumens/watt)							
High Intensity Discharge	EPACT 2005		Metal Halide Ballast Improvement								
Water Heater	EF 0.97										
Walk-in Refrigerator/Freezer	EISA 2007		10-38% more efficient								
Reach-in	EPACT 2005		40% more efficient								
Glass Door Display	EPACT 2005		12-28% more efficient								
Open Display Case	EPACT 2005		10-20% more efficient								
Ice maker	EPACT 2005			15% more efficient							
Pre-rinse Spray Valve	1.6 GPM				1.0 GPM						
Motors	EISA 2007	Expanded EISA 2007									

Table 5. Forecasted View of Relevant Non-Residential Energy Efficiency Code

Technology	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Central AC	SEER 13										
Room AC	EER 11.0										
Electric Resistance	Space Heating										
Heat Pump	SEER 14.0/HSPF 8.0										
Water Heater (<=55 gallons)	EF 0.95										
Water Heater (>55 gallons)	Heat Pump Water Heater										
Screw-in/Pin Lamps	Advanced Incandescent (20 lumens/watt)					Advanced Incandescent (45 lumens/watt)					
Linear Fluorescent	T8 (89 lumens/watt)			T8 (92.5 lumens/watt)							
Refrigerator	25% more efficient										
Freezer	25% more efficient										
Clothes Washer	MEF 1.72 for top loader			MEF 2.0 for top loader							
Clothes Dryer	5% more efficient (EF 3.17)										
Furnace Fans	Conventional				40% more efficient						

The impact of energy efficiency, including codes and standards, is expected to reduce residential load, commercial load, and industrial lighting load in total by over 5%, as shown in Figure 12.

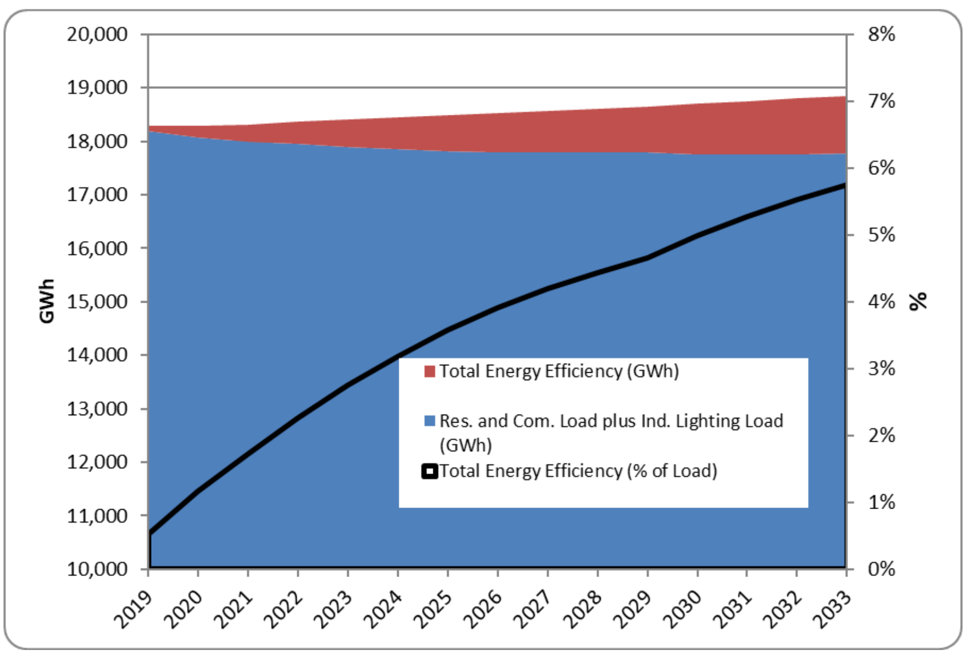

Figure 12. Total Energy Efficiency (GWh) Compared w/Total Residential & Commercial Load (GWh)

3.4.3 DSM Impact on Peak Demand

Peak demand, measured in MW, can be thought of as the amount of power used at the time of maximum coincident customer usage. 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. This happens as a result of the near-simultaneous use of air conditioning by the majority of customers, as well as the normal use of other appliances, commercial equipment, and (industrial) machinery. At other times during the day, and throughout the year, the use of power is lower. However, as a member of PJM, the Company's summer peak demand coincident with the RTO is a criterion for determining the Company's capacity obligation.

As peak demand grows with the economy and population, new generating capacity must ultimately be built. To defer construction of new power plants, the amount of power consumed at the peak can be reduced. This can be addressed several ways:

- *Interruptible loads*. This refers to a contractual agreement between the utility and a large consumer of power, typically an industrial customer. In return for reduced rates, an industrial customer allows the utility to "interrupt" or reduce power consumption during peak periods, freeing up that capacity for use by other consumers.
- *Direct load control*. Very much like an (industrial) interruptible load, but accomplished with many more, smaller, individual loads. Commercial and residential customers, in exchange for monthly credits or payments, allow the energy manager to deactivate or cycle discrete appliances, typically air conditioners, hot water heaters, lighting banks, or pool pumps during periods of peak demand. These power interruptions can be accomplished through radio signals that activate switches or through a digital "smart" meter that allows activation of thermostats and other control devices.
- *Time-differentiated rates*. This offers customers different rates for power at different times during the year and even the day. During periods of peak demand, power would be relatively more expensive, encouraging conservation. Rates can be split into as few as two rates (peak and off-peak) to as often as 15-minute

increments in what is known as "real-time pricing." Accomplishing real-time pricing requires digital (smart) metering.

- *EE measures*. If the appliances that are in use during peak periods use less energy to accomplish the same task, peak energy requirements will likewise be less.
- *Voltage Regulation*. Certain technologies, such as Conservation Voltage Reduction or Volt VAR optimization can be deployed that allow for improved monitoring of voltage throughout the distribution system. The ability to deliver electricity at design voltages improves the efficiency of many end use devices, resulting in less energy consumption.

What may not be apparent is that, with the exception of EE and voltage regulation measures, the remaining DR programs do not significantly reduce the amount of energy consumed by customers. Less energy may be consumed at the time of peak load, but that energy will be consumed at some point during the day. For example, if rates encourage customers to avoid running their clothes dryer at 4:00 P.M., then they will run it at some other point in the day. This is often referred to as load shifting. Load shifting may reduce usage during the system peak, but ultimately, the same, or similar, amount of energy will be used at a different time unless that consumption can be avoided through some type of end-use direct load control or pricing strategy.

3.4.3.1 Existing Levels of Demand Response (DR)

I&M currently has active DR programs totaling 272MW of peak DR capability. The majority of this DR is achieved through interruptible load agreements. A smaller portion is achieved through direct load control. In 2015 I&M launched a DR program for residential customers. Demand reduction is achieved by remotely managing customer thermostat set-points during periods of high demand in the summer. Each participating resident is compensated for this service with an incentive payment. The current Indiana program includes approximately 2,400 residential customers that can provide up to 2.9MW in demand savings. I&M's Michigan jurisdiction has a similar program.

3.4.3.2 Energy Efficiency (EE)

EE measures reduce bills and save money for customers. The trade-off is the up-front investment in a building/appliance/equipment modification, upgrade, or new technology. If consumers conclude that the new technology is a viable substitute and will pay them back in the form of reduced bills over an acceptable period, they will adopt it.

EE measures most commonly include efficient lighting, weatherization, efficient pumps and motors, efficient Heating, Ventilation and Air Conditioning (HVAC) infrastructure, and efficient appliances. Often, multiple measures are bundled into a single program that might be offered to either residential or commercial/industrial customers.

EE measures will reduce the amount of energy consumed but may have limited effectiveness at the time of peak demand. EE is viewed as a readily deployable, relatively low cost, and clean energy resource that provides many benefits. However, market barriers to EE may exist for the potential participant. To overcome participant barriers, a portfolio of EE programs may often include several of the following elements:

- Consumer education
- Technical training
- Energy audits
- Rebates and discounts for efficient appliances, equipment and buildings
- Industrial process improvements

The level of incentives (rebates or discounts) offered to participants is considered to be a major determinant in the pace of EE measure adoption.

Additionally, the speed with which programs can be rolled out also varies with the jurisdictional differences in stakeholder and regulatory review processes. The lead time can easily exceed a year for getting programs implemented or modified. This IRP begins adding new demand-side resources in 2020 that are incremental to programs that are currently approved or pending approval. I&M currently has approved EE programs in place in its Indiana and Michigan service territories and forecasts EE measures will reduce peak demand in 2019 by 18MW and reduce 2019 energy consumption by approximately 83.8GWh.

3.4.4 Distributed Generation (DG)

DG typically refers to small-scale customer-sited generation behind the customer meter. Common examples are Combined Heat and Power (CHP), residential and small commercial solar applications, and even wind. Currently, these sources represent a small component of demand-side resources, even with available federal tax credits and tariffs favorable to such applications. I&M's retail jurisdictions have "net metering" tariffs in place which currently allow excess generation to be credited to customers at the retail rate up to the amount of the customer's monthly bill.

The economics of DG, particularly solar, continue to improve. Figure 13 charts the rapid decline of expected installed solar costs, based on a combination of AEP market intelligence and the Bloomberg New Energy Finance's (BNEF) U.S. Renewable Energy Market Outlook forecast.

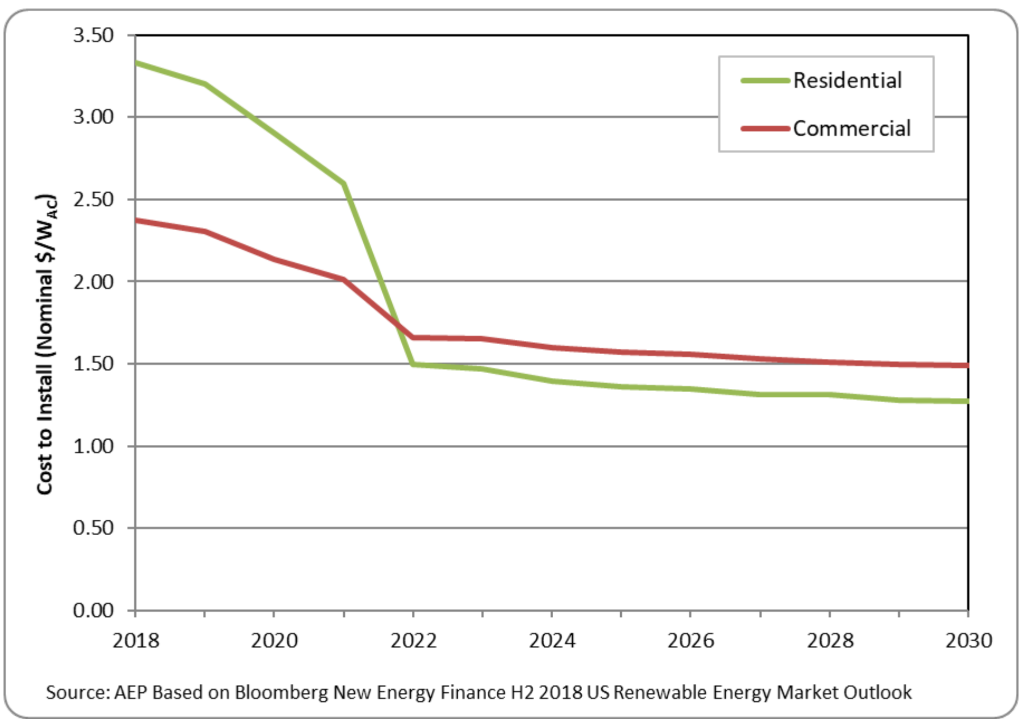

Figure 13. Residential & Commercial Forecasted Solar Installed Costs (Nominal W_{AC}$) for PJM

Prior to 2022, during the ITC phase out for residential systems, costs for residential customers are expected to decline rapidly. This decline, which is forecasted to bring residential costs down to commercial cost levels, is attributed to a shift from value-based pricing to cost-plus-margin pricing. Installers are expected to spend less on customer acquisition and less on customer specific solutions as they aim for the lowest cost installations possible.

3.4.4.1 Existing Levels of Distributed Generation (DG)

At the end of 2018 I&M has a total of 12.9MW of customer-installed DG consisting of 12.1MW in Indiana and 0.8MW in Michigan.

3.4.4.2 Impacts of Increased Levels of Distributed Generation (DG)

Increasing levels of DG present challenges for the Company from a distribution planning perspective. Higher penetration of DG can potentially mask the true load on distribution circuits and stations if the instantaneous output of connected DG is not known, which can lead to under-planning for the load that must be served should DG become unavailable. Increased levels of DG could lead to a requirement that DG installations include smart inverters so that voltage and other circuit parameters can be controlled within required levels. Additional performance monitoring capabilities for DG systems will facilitate accurate tracking and integration of DG generators into the existing resource mix.

Currently, DG applicants in I&M's Indiana and Michigan jurisdictions are required to fund any improvements needed to mitigate impacts to the operation and power quality of affected distribution stations and circuits. As DG penetration grows there is potential that the "next" applicant would be required to fund improvements that are a result of the aggregate impacts of previous DG customers because the incremental impact of the "next" customer now drives a need for improvements. This could lead to inequities among DG customers if necessary improvements are not planned appropriately.

3.4.5 Electric Energy Consumption Optimization (EECO)

EECO (also known as Volt VAR Optimization, or VVO) represents a form of voltage control that allows the grid to operate more efficiently. Depicted at a high-level in Figure 14, with EECO sensors and intelligent controllers monitor load flow characteristics and direct controls on capacitor and voltage regulating equipment to optimize power factor and voltage levels. Power factor is the ratio of real power to apparent power, and is a characteristic of electric power flow which is controlled to optimize power flow on an electric network. Power factor optimization also improves energy efficiency by reducing losses on the system. EECO enables Conservation Voltage Reduction (CVR) on a utility's system. CVR is a process by which the utility systematically reduces voltages in its distribution network, resulting in a proportional reduction of load on the network. Voltage optimization can allow a reduction of system voltage that still maintains minimum levels needed by customers, thereby allowing customers to use less energy without any changes in behavior or appliance efficiencies. I&M has approximately 50 distribution circuits with CVR installed in its Indiana service territory and 3 distribution circuits in its Michigan jurisdiction. I&M's CVR results show that a range of 0.7% to 1.2% of energy demand reduction for each 1% voltage reduction is possible.

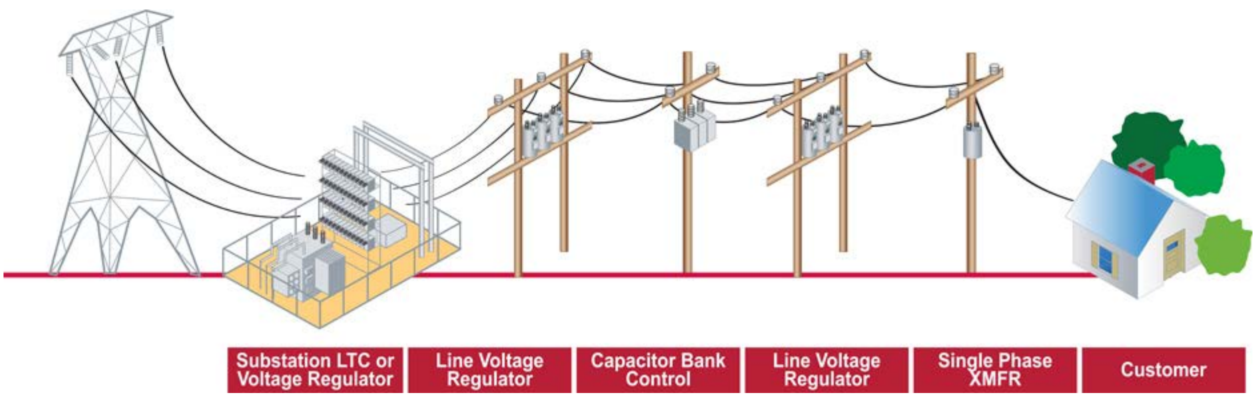

Figure 14. EECO Schematic

While there is no "embedded" incremental EECO load reduction impacts implicit in the base load forecast case, EECO has been modeled as a unique EE resource.

3.5 AEP-PJM Transmission

3.5.1 General Description

The AEP eastern transmission system (Eastern Zone) consists of the transmission facilities of the ten eastern AEP operating or Transmission companies (APCo, Ohio Power Company [OPCo], Indiana Michigan Power [I&M], Kentucky Power Company [KPCo], Wheeling Power Company [WPCo], Kingsport Power Company [KgPCo], AEP Indiana Michigan Transmission on Company, AEP Kentucky Transmission Company, AEP Ohio Transmission Company, and AEP West Virginia Transmission Company). The Eastern Zone is composed of approximately 14,800 miles of circuitry operating at or above 100kV, The Eastern Zone includes over 2,100 miles of 765kV transmission lines overlaying 3,500 miles of 345kV lines and over 8,900 miles of 138kV circuitry. This expansive system allows the economical and reliable delivery of electric power to approximately 21,660 MW of customer demand connected to the AEP eastern transmission system that takes transmission service under the PJM open access transmission tariff.

The AEP eastern transmission system is part of the Eastern Interconnection, the most integrated transmission system in North America. The entire AEP eastern transmission system is located within the Reliability*First* Corporation (RFC) geographic area. On October 1, 2004, AEP's eastern zone joined the PJM Regional Transmission Organization (RTO) and now participates in the PJM markets.

The AEP eastern transmission system can be influenced by both internal and external factors from its geographical location, expanse, and numerous interconnections. Facility outages, load changes, or generation re-dispatch on neighboring companies' systems, in combination with power transactions across the interconnected network, can affect power flows on AEP's transmission facilities. As a result, the AEP eastern transmission system is designed and operated to perform adequately even with the outage of its most critical transmission elements or the unavailability of generation. The eastern transmission system conforms to the NERC Reliability Standards and applicable RFC standards and performance criteria.

Despite the robust nature of the eastern transmission system, certain outages coupled with extreme weather conditions and/or power-transfer conditions can potentially stress the system beyond acceptable limits. The most significant 765kV transmission line enhancement was the construction of a 90-mile 765kV transmission line from Wyoming Station in West Virginia to Jacksons Ferry Station in Virginia completed in 2006. In addition, Extra High Voltage (EHV) transformer capacity has been increased at various stations across the eastern transmission system.

AEP's eastern transmission system assets are aging. Figure 15 below demonstrates the development of that Transmission Bulk Electric System. In order to maintain reliability, significant investments will be necessary over the next decade to address the aging infrastructure and assets.

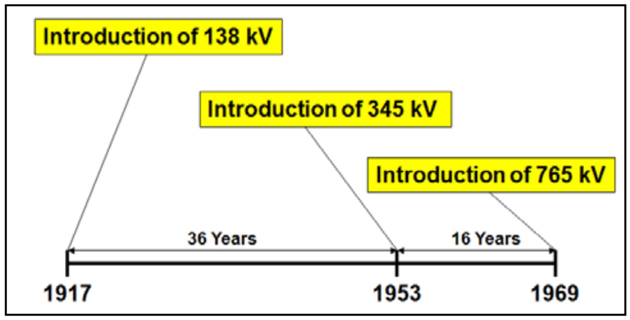

Figure 15. AEP Eastern Transmission System Development Milestones

Over the years, AEP, and more recently PJM, entered into numerous study agreements to assess the impact of the connection of potential merchant generation to the eastern transmission system. AEP companies, in conjunction with PJM, have interconnection agreements in their service territories with several merchant plant developers. Several generation additions are planned to be connected to the eastern transmission system over the next several years (including upgrades to existing facilities, once studied and approved through the PJM Generation Interconnection queue process[7], and based on executed agreements as of December 31st, 2018). There are also significant amounts of merchant generation under study for potential interconnection.

The integration of the merchant generation now connected to the eastern transmission system required incremental transmission system upgrades, such as installation of larger capacity transformers and circuit breaker replacements. None of these merchant facilities required major transmission upgrades that significantly increased the capacity of the transmission network. Other transmission system enhancements will be required to match general load growth and allow the connection of large load customers and any other generation facilities. In addition, transmission modifications may be required to address changes in power flow patterns and

[7] PJM Generation Interconnection queue is located at: https://www.pjm.com/planning/services-requests/interconnection-queues.aspx

changes in local voltage profiles resulting from operation of the PJM and adjacent markets, such as MISO and NYISO.

The transmission line circuit miles in I&M's Indiana service territory include approximately 610 miles of 765kV, 1,417 miles of 345kV, 1,521 miles of 138kV, 475 miles of 69kV, and 394 miles of 34.5kV lines. I&M's Michigan service territory includes approximately 16 miles of 765kV, 234 miles of 345kV, 234 miles of 138kV, 298 miles of 69kV, and 100 miles of 34.5kV lines.

3.5.2 Transmission Planning Process

AEP and PJM coordinate the planning of the transmission facilities in the AEP Eastern Zone through a "bottom up/top down" approach. AEP will continue to develop transmission expansion plans to meet the applicable reliability criteria in support of PJM's transmission planning process. PJM will incorporate AEP's expansion plans with those of other PJM member utilities and then collectively evaluate the expansion plans as part of its Regional Transmission Expansion Plan (RTEP) process. The PJM assessment will ensure consistent and coordinated expansion of the overall bulk transmission system within its footprint. In accordance with this process, AEP will continue to take the lead for the planning of its local transmission system under the provisions of Schedule 6 of the PJM Operating Agreement. By way of the RTEP, PJM will ensure that transmission expansion is developed for the entire RTO footprint via a single regional planning process, ensuring a consistent view of needs and expansion timing while minimizing expenditures. When the RTEP identifies system upgrade requirements, PJM determines the individual member's responsibility as related to construction and costs to implement the expansion. This process identifies the most appropriate, reliable and economical integrated transmission reinforcement plan for the entire region, while blending the local expertise of the transmission owners such as I&M with a regional view and formalized open stakeholder input.

AEP's transmission planning criteria are consistent with North American Electric Reliability Corporation (NERC) and RFC reliability standards. The AEP planning criteria are filed with FERC annually as part of AEP's FERC Form 715 and these planning criteria are posted on the AEP website[8]. Using these criteria, limitations, constraints and future potential deficiencies on the AEP transmission system are identified. Remedies are identified and budgeted as appropriate to ensure that system enhancements will be timed to address anticipated deficiencies.

PJM also coordinates its regional expansion plan on behalf of the member utilities with the neighboring utilities and/or RTOs, including the MISO, to ensure inter-regional reliability. The Joint Operating Agreement between PJM and the MISO provides for joint transmission planning.

3.5.3 System-Wide Reliability Measures

Transmission reliability studies are conducted routinely for seasonal, near-term, and long-term horizons to assess the anticipated performance of the transmission system. The reliability impact of resource adequacy (either supply or demand side) would be evaluated as an inherent part of these overall reliability assessments. If reliability studies indicate the potential for inadequate transmission reliability, transmission expansion alternatives and/or operational remedial measures would be identified.

3.5.4 Evaluation of Adequacy for Load Growth

As part of the on-going near-term/long-term planning process, AEP and PJM use the latest load forecasts along with information on system configuration, generation dispatch, and system transactions to develop models of the AEP transmission system. These models are the foundation for conducting performance appraisal studies based on established criteria to determine the potential for overloads, voltage problems, or other unacceptable operating problems under adverse system conditions. Whenever a potential problem is identified, PJM and AEP seek solutions to avoid the occurrence of the problem. Solutions may include operating procedures or capital transmission project reinforcements. Through this on-going process, AEP works diligently to maintain an adequate transmission system able to meet forecasted loads with a high degree of reliability.

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[8]https://www.aep.com/about/codeofconduct/OASIS/TransmissionStudies/

In addition, PJM performs a Load Deliverability assessment on an annual basis using a 90/10[9] load forecast for areas that may need to rely on external resources to meet their demands during an emergency condition.

3.5.5 Evaluation of Other Factors

As a member of PJM, and in compliance with FERC Orders 888 and 889, AEP is obligated to provide sufficient transmission capacity to support the wholesale electric energy market. In this regard, any committed generator interconnections and firm transmission services are taken into consideration under AEP's and PJM's planning processes. In addition to providing reliable electric service to AEP's retail and wholesale customers, PJM will continue to use any available transmission capacity in AEP's eastern transmission system to support the power supply and transmission reliability needs of the entire PJM – MISO joint market.

A number of generation requests have been initiated in the PJM generator interconnection queue. AEP, through its membership in PJM, is obligated to evaluate the impact of these projects and construct the transmission interconnection facilities and system upgrades required to connect any projects that sign an interconnection agreement. The amount of this planned generation that will actually come to fruition is unknown at this time.

3.5.6 Transmission Expansion Plans

The transmission system expansion plans for the AEP eastern transmission system are developed and reviewed through the PJM stakeholder process to meet projected future requirements. AEP and PJM use power flow analyses to simulate normal conditions, and credible single and double contingencies to determine the potential thermal and voltage impact on the transmission system in meeting the future requirements.

As discussed earlier, AEP, in coordination with PJM, will continue to develop transmission reinforcements to serve its own load areas to ensure compatibility, reliability and cost efficiency.

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[9] 90% probability that the actual peak load will be lower than the forecasted peak load and 10% probability that the actual peak load will be higher than the forecasted peak load.

3.5.7 Transmission Project Descriptions

A list and discussion of transmission projects that have recently been completed, are presently underway or planned in the I&M service area can be found in Section 3.5.9 of this report. In addition, several other projects beyond the I&M service territory have also been completed or are underway across the AEP Eastern Zone. While they do not directly impact I&M, such additions contribute to the robust health and capacity of the overall transmission grid, which also benefit Indiana customers.

AEP's eastern transmission system is anticipated to continue to perform reliably for the upcoming peak load seasons. AEP will continue to assess the need to expand its system to ensure adequate reliability for I&M's customers in Indiana and Michigan. AEP anticipates that incremental transmission expansion will continue to provide for expected load growth.

3.5.8 FERC Form 715 Information

A discussion of the AEP Eastern Zone reliability criteria for transmission planning, as well as the assessment practice used, is provided in AEP's 2019 FERC Form 715 Annual Transmission Planning and Evaluation Report. That filing also provides pertinent information on power flow studies and an evaluation and continued adequacy assessment of AEP's eastern transmission system.

As the transmission planner for AEP and AEP eastern subsidiaries, including I&M, PJM performs all required studies to assess the robustness of the Bulk Electric System. All the models used for these studies are created by and maintained by PJM with input from all transmission owners, including AEP and its subsidiaries. Information about current cases, models, or results can be requested from PJM directly. PJM is responsible for ensuring that AEP meets all NERC transmission planning requirements, including stability of the system.

Performance standards establish the basis for determining whether system response to credible events is acceptable. Depending on the nature of the study, one or more of the following performance standards will be assessed: thermal, voltage, relay, stability, and short circuit. In general, system response to events evolves over a period of several seconds or more. Steady state conditions can be simulated using a power flow computer program. A short circuit program can provide an estimate of the large magnitude currents, due to a disturbance, that must be detected by protective relays and interrupted by devices such as circuit breakers. A stability program simulates the power and voltage swings that occur as a result of a disturbance, which could lead to undesirable generator/relay tripping or cascading outages. Finally, a post contingency power flow study can be used to determine the voltages and line loading conditions following the removal of faulted facilities and any other facilities that trip as a result of the initial disturbance.

The planning process for AEP's transmission network embraces two major sets of contingency tests to ensure reliability. The first set, which applies to both bulk and local area transmission assessment and planning, includes all significant single contingencies. The second set, which is applicable only to the Bulk Electric System, includes multiple and more extreme contingencies. For the eastern AEP transmission system, thermal and voltage performance standards are usually the most constraining measures of reliable system performance.

Sufficient modeling of neighboring systems is essential in any study of the Bulk Electric System. Neighboring company information is obtained from the latest regional or interregional study group models, the RFC base cases, the Eastern Interconnection Reliability Assessment Group (ERAG) Multiregional Modeling Working Group (MMWG) power flow library, the PJM base cases, and neighboring companies themselves. In general, sufficient detail is obtained to adequately assess all events, outages, and changes in generation dispatch, which are contemplated in any given study.

3.5.9 Transmission Project Details

AEP's eastern transmission system is anticipated to continue to perform reliably for the upcoming peak load seasons. AEP will continue to assess the need to expand its system to ensure adequate reliability for I&M's customers.

A list with a brief description of scope of certain I&M transmission projects that have recently been completed, are presently underway or planned is provided below. These projects contribute to the robust health and capacity of the overall transmission grid, which benefits all customers.

- Anchor Hocking: AEP has identified the Anchor Hocking – Price 69kV line as a line in need of rebuilding due to condition and performance of the circuit. AEP is rebuilding approximately 6.5miles of 69kV line.
    - 2019: $0.05 million
    - 2020: $0.1 million
- College Corner 138kV Rebuild: AEP has identified multiple asset renewal issues at the College Corner station including FK oil type breakers. AEP will be rebuilding College Corner in the clear and replacing a breaker at the Richmond remote end station.
    - 2019: $0.6 million
- Delaware 138kV UG: The Delaware – Selma Parker underground portion has been subject to multiple prolonged outages due to the age and condition of the underground build. AEP will rebuild approximately 2 miles of the Deer Creek – Delaware 138kV line, retire the 7 mile double circuit 138kV underground section, and reterminate it into Desoto 345/138kV station.
    - 2019: $0.7 million
    - 2020: $0.03 million
- Greentown Rehab: Upon study of the Greentown 765kV station, asset renewal and operational issues were identified across the 765kV yard. AEP is installing six 765kV circuit breakers, two 138kV breakers, replacing XF #1 and reterminating it into a 138kV breaker string.
    - 2019: $0.03 million
    - 2020: $0.1 million
- Hartford City Area Improvements: Network-wide overloads were identified in the Hartford City 69kV network. AEP is rebuilding the Hartford City – Armstrong line as Hartford City – Jay and building a new Armstrong Cork – Jay 2 line. In addition, AEP is rebuilding Bosman – Delaware as the 69kV Royerton – Strawboard. To accommodate this work, station work will be completed at Jay, Bosman, Strawboard, Hartford City, Royerton and Delaware stations.

- 2019: $0.8 million
- 2020: $4.4 million
- 2021: $4.4 million
- 2022: $0.01 million

• Hogan – Kenmore: This project will rebuild approximately 2 miles of aging and physically overloaded 34.5kV line and replace aging infrastructure. Due to congestion in the area, a portion of the line will be built as underground.
  - 2019: $0.0 million
  - 2020: $0.02 million
  - 2021: $0.01 million
  - 2022: $0.2 million

• Madison 34.5kV Replacements: AEP is recommending to rebuild the 34.5 kV voltage class at Madison in the clear within the station footprint.
  - 2019: $0.5 million
  - 2020: $1.2 million
  - 2021: $0.02 million

• Northern Muncie Area Improvements: The Delaware 34.5kV voltage class, the Delaware – Jay 20 mile 34.5kV line and the Delaware – Haymond 2.5 mile 34.5kV line have all been identified as rehab candidates. AEP is installing a new 138kV Perch station and retiring the 20 mile Delaware – Jay asset. AEP will also be rebuilding the Delaware – Haymond line as well as rebuilding the Delaware 34.5kV voltage class as a ring bus to address the issues identified.
  - 2019: $0.3 million
  - 2020: $3.0 million
  - 2021: $2.0 million

• Desoto Station Expansion: In order to bring the Desoto station up to current standards, AEP plans to install 4 345kV and 5 138kV circuit breakers, and a new transformer.
  - 2019: $0.2 million

- Eugene – Dequine – Meadow Lake Upgrades: This project will reconductor 45 miles of 345kV line between Eugene and Dequine station, and reconductor 14 miles of 345kV line between Dequine and Meadow Lake station. Multiple overloads were identified by PJM during its 2015 and 2016 regional transmission expansion plan. This project would address all overloads identified by PJM.
    - 2019: $1.7 million
    - 2020: $5.0 million
- Sorenson – Deer Creek 138kV Line Rebuild: AEP will rebuild 32 miles of the Delaware – Sorenson & Sorenson – Deer Creek 138 kV double circuit line, and rebuild 3 miles of the Deer Creek 138kV double circuit extension to address open conditions.
    - 2019: $0.03 million
- Strawton Area Improvements: AEP plans to upgrade the network to 69kV which will allow for retirement of a sizable portion of the remaining 34.5kV assets in the area.
    - 2019: $0.3 million
    - 2020: $1.3 million
    - 2021: $0.4 million
- Tanners Creek 345kV Breaker Expansion: PJM has identified multiple overloads at this station. AEP is replacing any bussing or equipment that is overloaded and will be installing breakers to bring this station up to standards.
    - 2019: $0.1 million
    - 2020: $0.9 million
    - 2021: $0.6 million
- Southern Muncie: AEP will be rebuilding the Hogan – 23rd street line as well as replacing significant assets in 23rd Street, Arnold Hogan, Medford and Blaine Street and will be installing the new Fuson station which will allow the retirement of Elmridge station.
    - 2019: $1.3 million
    - 2020: $4.9 million
    - 2021: $3.1 million

- 2022: $1.9 million

- Jay – Portland Area Improvements: AEP will be building a new 69kV feed from Jay station to North Portland station to address planning concerns. In addition to this, AEP will be de-radializing the Antiville station and will retire the Antiville Tap line.
  - 2019: $0.4 million
  - 2020: $1.8 million
  - 2021: $1.0 million
  - 2022: $0.3 million

- Jay – Allen Area Improvements: AEP has identified the Berne – South Decatur line as an overloading asset. AEP has also identified the Pennville – Allen line as in need of rehab. AEP will rebuild both the Berne – South Decatur and the Pennville – Allen line to mitigate these issues.
  - 2019: $0.6 million
  - 2020: $2.1 million
  - 2021: $2.0 million
  - 2022: $0.7 million

- Western Marion Area Improvements: AEP has identified condition and performance issues spread throughout the Western Marion area. In order to address these issues, AEP will be rebuilding the Grant – Marion and Deer Creek – Marion lines, rebuilding the Deer Creek 34.5kV voltage class, retiring the Deer Creek – Miller Ave line and will be adding a 138kV cap bank at Grant to maintain voltage levels.
  - 2019: $0.4 million
  - 2020: $3.6 million
  - 2021: $0.7 million
  - 2022: $0.1 million
- College Corner – Jay: AEP has identified the 62-mile Jay – College Corner line as in need of rehab. In order to address this line, AEP will be rebuilding the line asset.
  - 2019: $0.4 million
  - 2020: $3.0 million

 - 2021: $2.4 million
 - 2022: $0.2 million

- Berrien Springs Area Improvements: This project will replace several circuit breakers. The area improvements will transfer some load to a new station, Boxer. The introduction of a new 138kV source (Blossom Trail) near Eau Claire, MI will provide the opportunity to strengthen the grid and restore stability to the area. In addition, converting the line from Derby through Berrien to 69 kV will further strengthen this area.
    - 2019: $5.2 million
    - 2020: $2.4 million
- Lakeland Hospital Interconnection: Lakeland Memorial Hospital has requested to transfer existing load from current distribution service to 34.5 kV. This requisition proposes establishing a new 69 kV station, operating at 34.5 kV, to provide transmission service to the hospital. The customer owned 69kV and 12kV facilities will be built in a separate yard, approximately 120 feet away to ensure adequate separation.
    - 2019: $0.2 million
- PJM Generator Interconnection Queue AA2-116: Indeck Energy Services proposes to interconnect a 994 MW (994 MW Capacity) natural gas generating facility to the AEP Transmission System. This Point of interconnection will tie together the Cook – Kenzie Creek 345 kV circuit section and the Cook- East Elkhart 345 kV circuit section via a new switching station. Proposed Thomson station is to consist of six (6) 345 kV circuit breakers physically configured to provide for future expansion to a breaker and half bus arrangement, but initially operated as a ring-bus . There will be 4 345 kV line extensions required to loop through the proposed station. Thomson station is assumed to be located immediately adjacent to the existing transmission lines.

    - 2019: $0.06 million
    - 2020: ($0.1) million
    - 2021: ($0.2) million
- Valley Area Reinforcements: AEP is rebuilding the Valley – Glenwood Tap, Riverside – South Haven and Almena – Hartford line to 69kV standards. In addition to this, the

Valley – Almena line will also be rebuilt as a 138/69kV double circuit line. Almena station will have to have a 138kV high side installed to incorporate this new line. Hartford station will have a 138/69kV transformer added with high and low side protection to provide another source for the network. In addition to this, work is being done at Hartford, Riverside and Hagar station to address aging infrastructure needs.

  - 2019: $6.3 million
  - 2020: $3.5 million

- Hickory Creek Station Reinforcements: Three 138kV circuit breakers will be replaced along with 2 138/34.5kV transformers with an auto transformer. The 34.5kV and 69kV equipment will be retired with the exception of one transformer. The 34.5kV and 69kV line exits will be relocated to a new 69kV bus with 8 circuit breakers.

  - 2019: $0.04 million
  - 2020: $0.1 million
  - 2021: $1.0 million
  - 2022: $0.4 million

- Corey-Pokagon Rebuild to 138kV: The 27 miles of 69kV between Pokagon and Corey stations be rebuilt as a double circuit 138 kV and a new 138 kV line extension be constructed to Kenzie Creek station. In addition, construction of a new 138 kV line extension to Mottville station. At Pigeon River station, installation of a 69 kV capacitor bank. At Mottville station, installation of new 138 kV circuit breakers, 138 kV circuit switcher, and replacement of the 138/69-34.5 kV transformer. At Corey station, construction of a new 138 kV breaker and half yard with circuit breakers, installation of a 138 kV capacitor bank, a second 138/69-34.5 kV transformer, and replacement of all 69 kV circuit breakers. At Stone Lake station, installation of 69 kV circuit breakers. In addition, replacement of Wolverine 69 kV phase over phase switch, and installation of new 138 kV circuit breakers at Kenzie Creek.
  - 2019: $0.2 million
- Jackson Road 345kV CB Additions: This project is associated with the I&M T-Planning

program to eliminate 345kV MOABs where possible and add 345kV circuit breakers for increased reliability. Jackson Road 345kV circuit breaker additions will install 3 new (3000A, 63kA) circuit breakers. This will create a three breaker ring bus for the Cook circuit, Twin Branch circuit, and the Jackson Road Transformer. All 345kV MOABs will be eliminated at the station.

  - 2019: $0.7 million

- Central South Bend Reliability Project: Transmission planning is proposing to construct 2.5 miles of 69 kV underground transmission line in South Bend to address rehab and operational needs. This enables the retirement of Colfax – Kankakee 34.5kV line and conversion of the South Bend – West Side 34.5kV Line and the South Bend – Colfax 34.5kV line to 69kV operation as majority of the lines are built to 69kV standards but operate at 34.5kV. Converting the system to 69kV will address the load drop & pick concerns. Colfax and Drewry's Station will be complete station rebuilds because of asset renewal, space limitation and operational needs. St Mary's Station has some rehab needs and will be upgraded to accept 69kV service.
  - 2019: $5.1 million
  - 2020: $5.3 million
- Dragoon-Kline Improvements: AEP transmission will expand the existing Dragoon station, upgrade all switches along the 34.5kV corridor going from Dragoon to Kline, upgrade Russ St. switch, and rebuild a quarter mile of the existing South Bend – Dragoon 34.5kV line. The 138kV hard tap will be eliminated and reconfigure the 138kV yard with an in and out configuration, install a 138kV bus tie circuit breaker, install a second 138/69/34.5 autotransformer, and replace 4 34.5kV circuit breakers. Transmission will also upgrade risers at Kline and Virgil St. Stations.
  - 2019: $2.0 million
  - 2020: $4.3 million
- Kline Area Improvements: This project calls for replacement of transformer #4 34.5/4 kV at Twin Branch Hydro Station and 138/34kV transformer #1 at Kline Station. The oil filled 34.5 kV Circuit at Kline Station and Twin Branch Hydro Station will be replaced with new Circuit Breakers as well as 1 SF6 breaker at Twin Branch. A 138kV Circuit

Switcher on the high side of transformer #1 and a 138 kV Circuit Breaker towards Northeast (NIPSCO) station will be installed at Kline Station to eliminate the three terminal line configuration and the high speed ground switch on the high side of transformer #1.

  - 2019: $0.1 million
  - 2020: $0.7 million
  - 2021: $0.6 million

- South Bend 138kV Line Rebuild: Planning is proposing to rebuild the 1930's vintage South Bend – New Carlisle double circuit 138kV Line and the 1925's vintage Twin Branch – South Bend 138kV Line. These lines have been operating for more than 90 years. This will address the aging infrastructure, system needs as well as open condition concerns on the conductor and structures.
  - 2019: $0.7 million
  - 2020: $1.4 million
- New Carlisle-Bosserman Improvements: The project will be to construct two 138/12 kV distribution stations, Bootjack and Marquette, to replace Silver Lake 34.5 kV and Springville 69 kV stations. Rebuild sections of the LaPorte Junction-New Carlisle/New Buffalo 34.5 kV line to 138 kV to establish Bootjack-Olive 138 kV circuit. Install a three way phase over phase switch, Kuchar, near Liquid Carbonics and construct a new 138 kV line between Bootjack and Kuchar. Construct a 138 kV extension to Marquette station by taping the Bosserman-Liquid Carbonics 138 kV line. Install a 138/12 kV transformer at New Carlisle and terminate Bosserman-Olive 138 kV ckt at New Carlisle.
  - 2019: $1.5 million
- Osolo Area Improvements: Planning is proposing to replace transformer #1 138/69/34.5kV at East Elkhart Station. The project will replace one 34.5kV circuit breaker at East Elkhart Station and 2 Osolo Station. 138kV Circuit Breakers and Circuit Switcher will be added at Osolo Station to get rid of the three terminal line and provide improved reliability to the 40 MVA Distribution load.
  - 2019: $0.4 million

- Anthony Lakeside 34.5kV Rebuild: AEP will rebuild the existing Anthony-Lakeside 34.5 kV circuit.
    - 2019: $0.4 million
    - 2020: $0.2 million

- City of Fort Wayne Area Improvements: To better serve the customers in the downtown Fort Wayne area, I&M is proposing to introduce a second 138 kV source to Spy Run station by rebuilding an existing 34.5 kV line as a double circuit tower line. One side will be operated at 138 kV while the other will remain at 34.5 kV. The 34.5 kV network will also be upgraded as needed to accommodate the new 138 kV source and rearrangement of the distribution network.
    - 2019: $1.8 million
- OSCP Auburn-Kendallville 69kV: The Auburn-Kendallville 69 kV line rebuild and circuit breaker replacements will rebuild the remaining portions of transmission line on each side of Clipper Loop and replace FK breakers at Kendallville and Albion stations.
    - 2019: $1.9 million
    - 2020: $0.1 million
- SDI Service Enhancements: This project will construct a new 138 kV switching station between Grabill and South Hicksville, extend a greenfield 138 kV line (~3.5 miles) from this station to Butler-North Hicksville line, and construct a new greenfield 345/138 kV station near SDI South Butler and Wilmington. From this 345/138 kV station, a greenfield double circuit 138 kV line (~1.5 miles) will be extended to Auburn-Ferrous line near New Millennium. From New Millennium, a greenfield single circuit 138 kV will be extended to Butler-North Hicksville line and loop into the new 345/138 kV station, the Collingwood-South Butler 345 kV line and Dunton Lake-Wilmington 138 kV line. This project will address the 300MW load loss criteria violation at South Butler station while providing a new EHV source into the area.
    - 2019: $2.1 million
    - 2020: $3.9 million
    - 2021: $6.9 million

3.6 Distribution Opportunities

3.6.1 Grid Modernization

I&M engages in electric distribution grid planning to maintain and improve safety, improve system reliability and security and to help I&M create an enabling platform in which I&M's customers will be able to integrate. Projects under consideration include vegetation management, distribution automation, advanced metering infrastructure, distribution hardening, energy storage and micro grids.

Distribution grid planning projects do not typically have a significant demand or energy impact associated with them. As a result, the evaluation of these types of projects is, for the large part and due to their nature, different than the evaluation of supply- and demand-side generation resources that is traditionally part of the IRP process. In addition, because the distribution grid transformation projects costs are assumed to be common in each IRP resource portfolio, I&M did not consider associated incremental costs in the IRP modeling. The Company has, however, included the cost of 50MW of energy storage and 54MW of micro/mini grids in the modeling and its Preferred Plan. Please refer to Section 5.3.

4.0 Modeling Parameters

4.1 Modeling and Planning Process – An Overview

The objective of a resource planning effort is to recommend a system resource plan that balances least-cost objectives with planning flexibility, asset mix considerations, adaptability to risk, conformance with applicable North American Electric Reliability Corporation (NERC) and RTO criteria. In addition, given the unique impact of fossil-fired generation on the environment, the planning effort must ultimately be in concert with anticipated long-term requirements as established by the EPA-driven environmental compliance planning process.

The information presented with this IRP includes descriptions of assumptions, study parameters, methodologies, and results, including the integration of traditional supply-side resources, renewable energy resources, distributed generation and DSM programs.

In general, assumptions and plans are reviewed and modified periodically when new information becomes available. On-going analysis is required by multiple disciplines across I&M and AEP to ensure that market structures and governances, technical parameters, regulatory constructs, capacity supply, energy adequacy and operational reliability, and environmental mandate requirements are current to ensure optimal capacity resource planning.

Further influencing this process are a growing number of federal and state initiatives that address many issues relating to industry restructuring, customer choice, and reliability planning. Currently, fulfilling a regulatory obligation to serve native load customers represents one of the cornerstones of the I&M IRP process. Therefore, as a result, the "objective function" of the modeling applications utilized in this process is the establishment of the least-cost plan, with *cost* being more accurately described as *revenue requirement* under a traditional ratemaking construct.

That does not mean, however, that the most appropriate plan is the one with the absolute least cost over the planning horizon evaluated. Other factors were considered in the determination of the Plan. To challenge the robustness of the IRP, sensitivity analyses were performed to address these factors.

This overall process reflects consideration of options for maintaining and enhancing rate stability; economic development; and service reliability.

4.2 Methodology

The IRP process aims to address the gap between resource needs and current resources. Given the various assets and resources that can satisfy this expected gap, a tool is needed to sort through the myriad of potential combinations and return an optimum solution. *Plexos*® is the primary modeling application used by I&M for identifying and ranking portfolios that address the gap between needs and current available resources.[10] Given resource cost and performance parameters, a set of economic conditions that include long-term fuel prices, capacity costs, energy costs, emission-based pricing including CO_2, projections of energy usage and peak demand, *Plexos*® will return the optimal portfolio that meet the resource need. Portfolios created under similar pricing scenarios may be ranked on the basis of cost, or the cumulative present worth (CPW), of the resulting stream of revenue requirements. The least cost option is considered the optimum portfolio for that unique input parameter scenario.

4.3 The Fundamentals Forecast

The Fundamentals Forecast is a long-term, weather-normalized commodity market forecast. The forecast is not specific to I&M or to this IRP analysis; rather, it is made available to AEPSC and all AEP operating companies after completion. Within AEP the forecast is referenced for purposes such as resource planning, capital improvement analyses, fixed asset impairment accounting, strategic planning and others. These projections cover the electricity market within the Eastern Interconnect (which includes PJM and the Southwest Power Pool), the Electric Reliability Council of Texas (ERCOT) and the Western Electricity Coordinating Council (WECC)). The Fundamentals Forecasts include: 1) monthly and annual regional power prices (in both nominal and real dollars); 2) prices for various qualities of Central Appalachian (CAPP), Northern Appalachian (NAPP), Illinois Basin (ILB), Powder River Basin (PRB), and Colorado coals; 3) monthly and annual locational natural gas prices, including the benchmark Henry Hub;

[10] *Plexos*® is a production cost-based resource optimization model, which was developed and supported by Energy Exemplar, LLC. The *Plexos*® model is currently licensed for use in 37 countries throughout the world.

4) nuclear fuel prices; 5) SO_2, NOx, and CO_2 values; 6) locational implied heat rates; 7) electric generation capacity values; 8) renewable energy subsidies; and 9) inflation factors, among others.

The primary tool used for the development of the North American long-term energy market pricing forecasts is the Aurora energy market simulation model. It iteratively generates zonal, but not company-specific, long-term capacity expansion plans, annual energy dispatch, fuel burns and emission totals from inputs including fuel, load, emissions and capital costs, among others. Ultimately, Aurora creates a weather-normalized, long-term forecast of the market in which a utility operates.

The Aurora energy market simulation model is widely used by utilities for integrated resource and transmission planning, power cost analysis and detailed generator evaluation. The database includes approximately 25,000 electric generating facilities in the contiguous United States, Canada and Baja Mexico. These generating facilities include wind, solar, biomass, nuclear, coal, natural gas, and oil. A licensed online data provider, ABB Velocity Suite, provides up-to-date information on markets, entities and transactions along with the operating characteristics of each generating facility, which are subsequently exported to the Aurora energy market simulation model.

The Fundamentals Forecast is a long-term, weather-normalized energy market forecast and there is the credible modeling expectation that each forecast-year experiences 30-year average heating and cooling degree-days. In fact, actual weather can deviate dramatically. The combination of both heating degree day departure from normal and above- or below-normal natural gas storage inventory levels are primary factors affecting any nearby deviation from weather-normalized values. Warmer-than-normal winters result in reduced natural gas demand and materially depressed natural gas prices. Understandably, the Polar Vortex winter of 2013-2014 had the opposite effects. When comparing actual results to a weather normalized forecast, it is imperative to account for these impacts.

AEPSC also has ample energy market research information available for its reference, which includes third-party consultants, industry groups, governmental agencies, trade press, investment community, AEP-internal expertise, various stakeholders, and others. Although no exact forecast inputs from these sources of energy market research information are utilized, an in-depth assessment of this research information can yield, among other things, an indication of the supply, demand, and price relationship (price elasticity) over a period of time. This price elasticity, when applied to the Aurora-derived natural gas fuel consumption, yields a corresponding change in natural gas prices – which is recycled through the Aurora model iteratively until the change in natural gas fuel consumption for the electric generation sector is de minimis. Figure 16 illustrates that any changes in input assumptions must be iteratively processed through Aurora to determine a new merit order of dispatch. It is this new merit order of dispatch that takes into account the effect of operating conditions across North America and, in turn, ultimately determines zonal energy market prices.

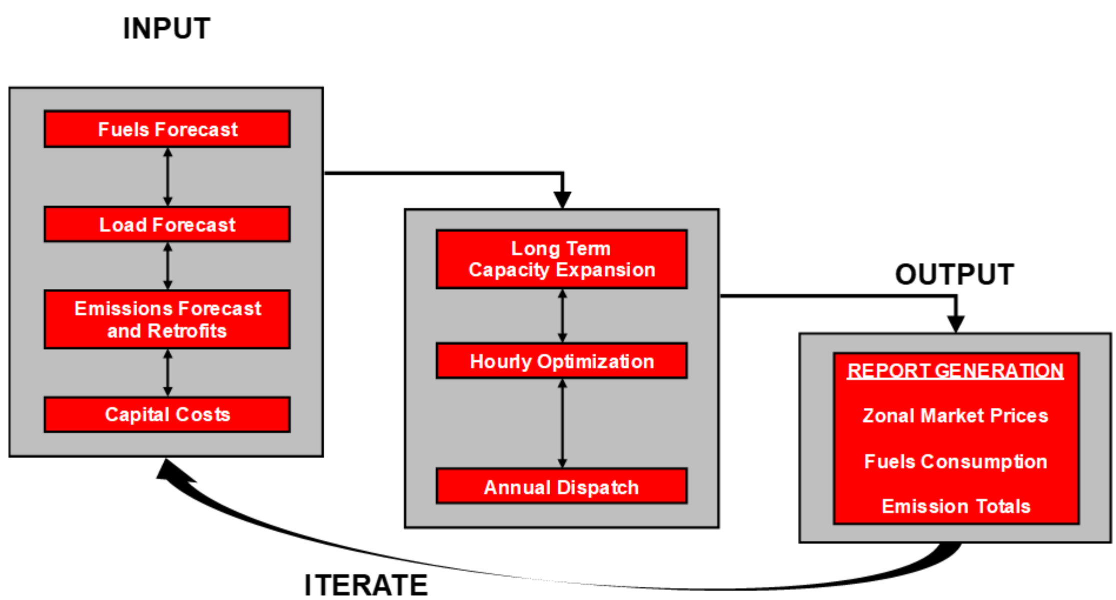

Figure 16. Long-term Power Price Forecast Process Flow

4.3.1 Commodity Pricing Scenarios

Four commodity-pricing scenarios were developed to construct resource plans for I&M under various long-term pricing conditions. In this Report, the four distinct long-term commodity-pricing scenarios that were developed are the Base Case, Lower Band, Upper Band, and No Carbon cases. The overall fundamentals forecasting effort was most recently completed in April of 2019. The associated cases were designed and generated to define a plausible range of outcomes surrounding the Base Case Fundamentals Forecast. The Lower and Upper Band forecasts 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. Renewable Energy Credits (REC) are assumed to be zero over the long term in all of the Fundamental Commodity price forecasts.

The Fundamentals Forecast employs a CO_2 dispatch burden (adder) on all existing fossil fuel-fired generating units that escalates 3.5% per annum from $15 per metric ton commencing in 2028. This CO_2 dispatch burden is a proxy for the many pathways CO_2 may take (e.g. renewables subsidies/penetration, voluntary and mandatory portfolio standards, exceptionally low natural gas prices, considerable reduction in battery storage costs) in addition to any regulation to impose fees on the combustion of carbon-based fuels.

It is the assessment of Company experts that the likelihood of any federal climate legislation is very low over the next three years and still unlikely through the tenure of the 116th Congress. With 2021-2023 as the earliest reasonable date for a climate proposal to pass through committee, reach the floor and be approved by house for eventual passage, there will be an implementation period of approximately five years (as seen in previous climate proposals). Thus, 2028 is the earliest reasonable projection as to when such legislation *could* become effective.

The Fundamentals Forecast is not merely concerned with the status of regulations and other current conditions that affect prices, but instead must also reflect reasonable expectations regarding future conditions that affect prices. As such, the carbon price proxy used for fundamentals forecasting is a reasonable assessment of future costs based on the status for carbon regulations and potential changes thereto.

The Base No Carbon case assumes there will be no regulations limiting CO_2 emissions throughout the entire forecast period.

4.3.2 Forecasted Fundamental Parameters

Figure 17 through Figure 22 illustrate the forecasted fundamental parameters (fuel, energy, capacity and CO_2 emission prices) that were used in the long-term optimization modeling for this IRP.

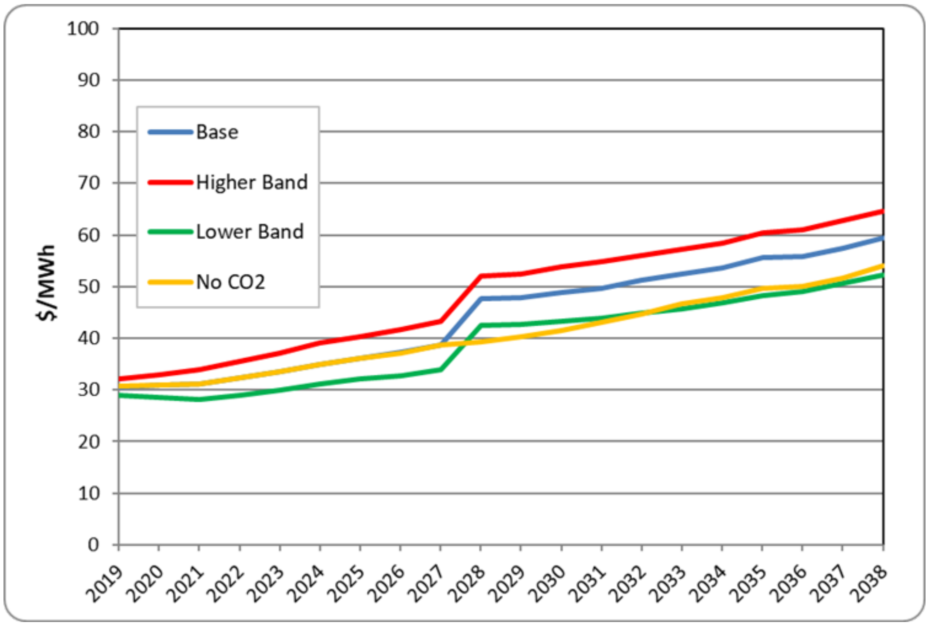

Figure 17. PJM On-Peak Energy Prices (Nominal $/MWh)

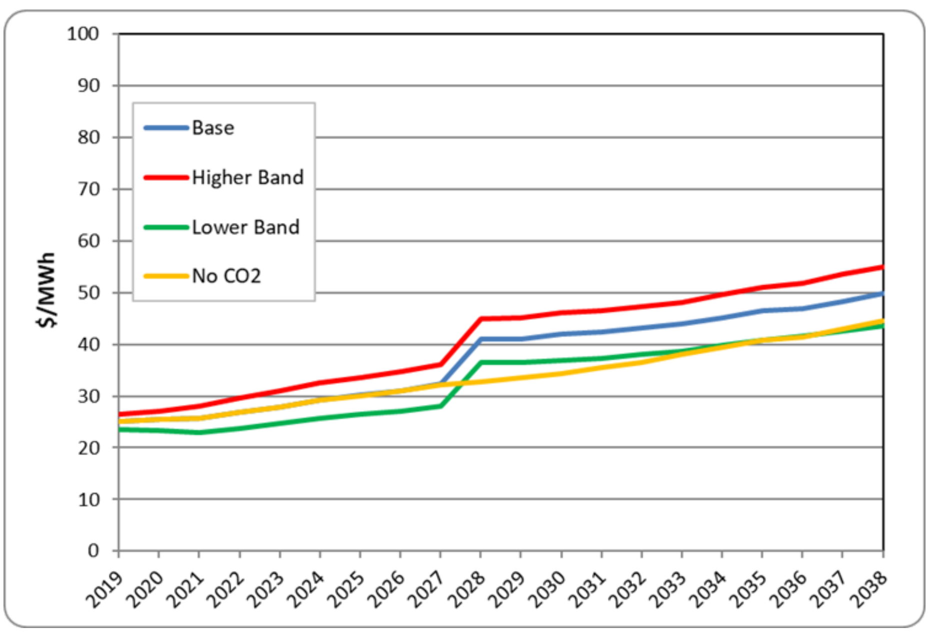

Figure 18. PJM Off-Peak Energy Prices (Nominal $/MWh)

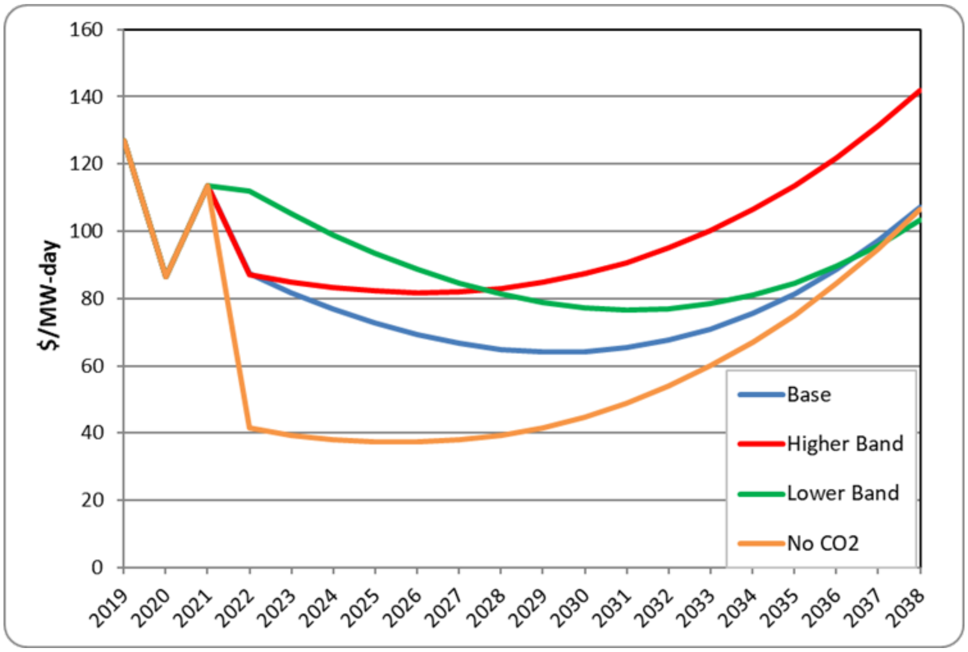

Figure 19. PJM Capacity Prices (Nominal $/MW-day)

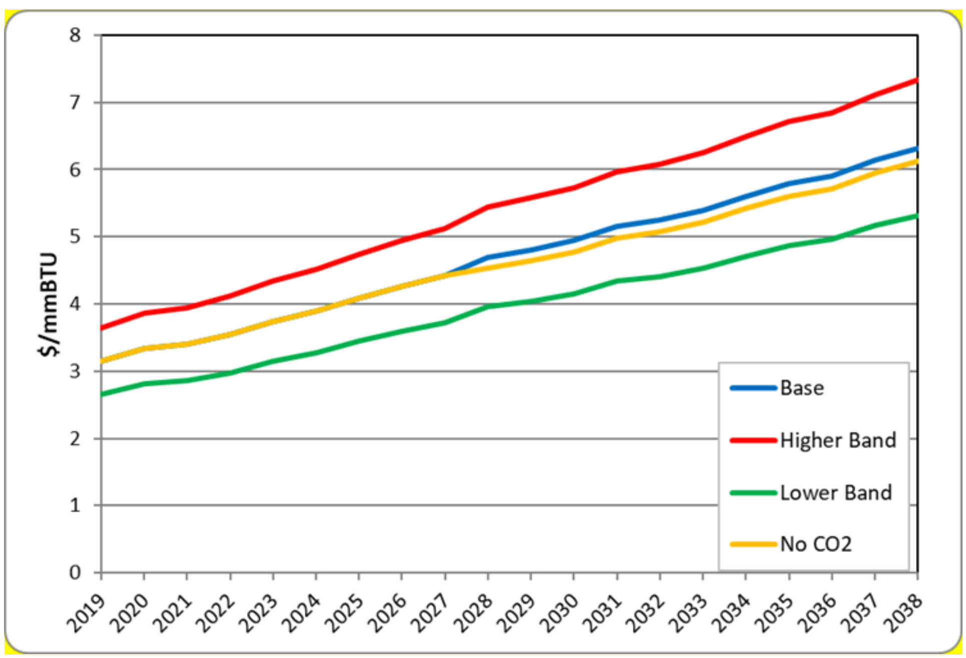

Figure 20. TCO (Delivered) Natural Gas Prices (Nominal $/mmBTU)

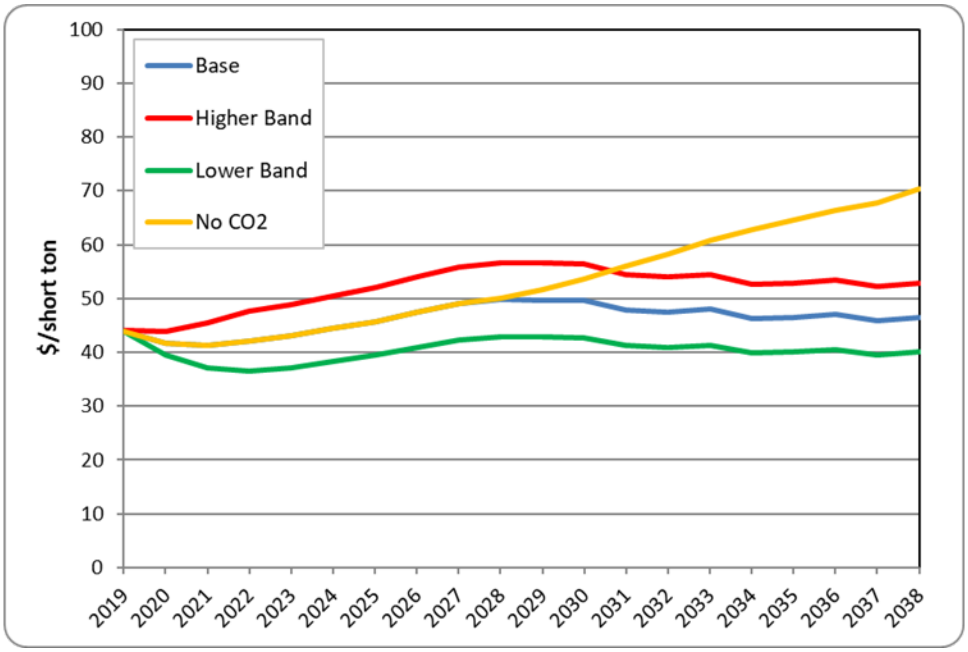

Figure 21. ILB 11,512 BTU/lb. Coal Prices (Nominal $/ton, FOB)

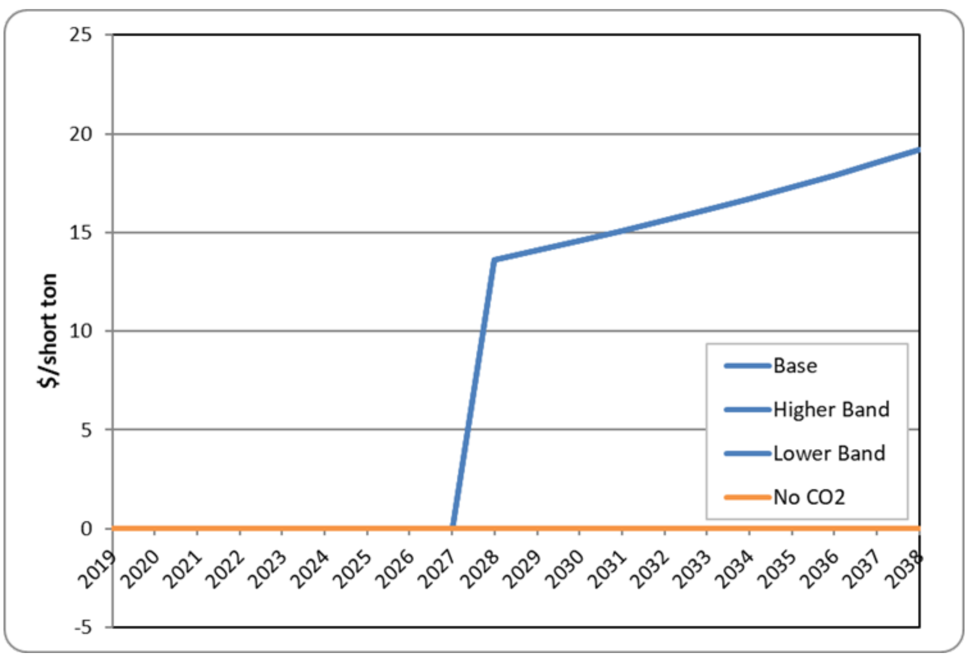

Figure 22. CO2 Prices (Nominal $/short ton)

4.4 Demand-Side Management (DSM) Program Screening & Evaluation Process

4.4.1 Overview

The process for evaluating DSM impacts for I&M is divided into two components: "existing DSM programs" and "incremental DSM programs." Existing DSM programs are those that are known or are reasonably well-defined, and follow a pre-existing process for screening and determining ultimate regulatory approval. The impacts of I&M's existing approved DSM programs are propagated throughout the long-term load forecast. Incremental DSM program impacts which are, naturally, less-defined, are developed with a dynamic modeling process using more generic cost and performance parameter data.

The potential incremental DSM programs were developed and ultimately modeled based on input from Applied Energy Group (AEG), an energy efficiency consultant that developed I&M's 2016 EE Market Potential Study (MPS). To maintain consistency with the work that had been performed to identify EE potential through I&M's MPS, AEG utilized the data from the MPS to develop inputs for modeling DSM in this IRP.

4.4.2 Achievable Potential (AP)

The amount of available EE is typically described in three sets: technical potential, economic potential, and achievable potential. AEG breaks down the achievable potential into a High Achievable Potential (HAP) and an Achievable Potential (AP), with the HAP having a higher utility cost than the AP. Briefly, the technical potential encompasses all known efficiency improvements that are possible, regardless of cost, and thus, whether or not it is cost-effective (i.e., all EE measures would be adopted if technically feasible). The logical subset of this pool is the economic potential. Most commonly, the total resource cost test is used to define economic potential. This compares the avoided cost savings achieved over the life of a measure/program with the cost to implement it, regardless of who paid for it and regardless of the age and remaining economic life of any system/equipment that would be replaced (i.e., all EE measures would be adopted if economic). The third set of efficiency assets is that which is achievable. As highlighted above, the HAP is the economic potential discounted for market barriers such as customer preferences and supply chain maturity; the AP is additionally discounted for programmatic barriers such as program budgets and execution proficiency.

Of the total technical potential, typically only a fraction is ultimately achievable and only then over time due to the existence of market barriers. The question of how much effort and money is to be deployed towards removing or lowering the barriers is a decision made by state governing bodies (legislatures, regulators or both).

The AP range is typically a fraction of the economic potential range. This achievable amount must be further split between what can or should be accomplished with utility-sponsored programs and what should fall under codes and standards.

4.4.3 Evaluating Incremental Demand-Side Resources

The *Plexos®* model allows the user to input incremental CHP, EE, DG, DR and VVO as resources, thereby considering such alternatives in the model on equal-footing with more traditional "supply-side" generation resource options.

4.4.3.1 Incremental Energy Efficiency (EE) Modeled

To determine the economic demand-side EE activity to be modeled that would be over-and-above existing EE program offerings in the load forecast, the potential and cost of incremental EE measure bundles, as well as the ability to expand current program measures, were determined based on measure attributes from I&M's 2016 MPS. These incremental measure bundles were available to be selected beginning in 2020. Given that each of I&M's jurisdictions have a subset of customers that are allowed to opt-out of participating in EE programs, the amount of load from these customers reduced the amount of economic potential used in the IRP by jurisdiction and thus not modeled.

To determine which end-uses are targeted and in what amounts, I&M looked at the measures from the MPS that were identified as having the most potential savings. These measures resulted in a list of twenty measures, ranked first through twentieth by savings potential, for each of the residential, commercial, and industrial sectors (The Top 20 Measures). For The Top 20 Measures, AEG provided information on a multitude of current and anticipated end-use measures including measure costs, energy savings, market acceptance ratios and program implementation factors. I&M and AEG utilized this data to develop "bundles" of future EE activity for the demographics and weather-related impacts of its service territory. Table 6, Table 7, and Table 8, list the individual measures considered for each sector.

Table 6. Residential Top Measures from Market Potential Study

Rank	Residential Measure	2019 Cumulative Energy Savings (MWh)	% of Total
1	Interior Lighting - LED Screw-In Lamps	71,419	42.5%
2	Exterior Lighting - LED Screw-in Lamps	29,857	17.8%
3	Thermostat - WIFI	17,324	10.3%
4	Interior Lighting - Exempted LED Screw-In Lamp[11]	17,242	10.3%
5	Refrigerator - Decommissioning and Recycling	6,201	3.7%
6	Water Heating - Water Heater - ES 2.0 Heat Pump	4,595	2.7%
7	Freezer - Decommisioning and Recycling	3,851	2.3%
8	Windows - High Efficiency	2,065	1.2%
9	Windows - Install Reflective Film	1,509	0.9%
10	Appliances - Air Purifier – ENERGY STAR	1,462	0.9%
11	Water Heater - Temperature Setback	1,061	0.6%
12	Cooling - Central AC – SEER 14	995	0.6%
13	Central AC - Maintenance	988	0.6%
14	Whole-House Fan - Installation	887	0.5%
15	Water Heater - Low-Flow Showerheads	815	0.5%
16	Water Heater - Pipe Insulation	775	0.5%
17	Appliances – Refrigerator – CEE TIER 1	696	0.4%
18	Insulation - Ceiling	693	0.4%
19	Appliances – Dehumidifier – ENERGY STAR	611	0.4%
20	Electronics - Personal Computers	553	0.3%
	Total Top Measures	**163,598**	**97.4%**
	Total Cumulative savings in 2019	**168,038**	**100%**

[11] Specialty LED bulbs.

Table 7. Commercial Top Measures from Market Potential Study[12]

Rank	Commercial Measure	2019 Realistic Achievable Cumulative Savings (MWh)	% of Total
1	Interior Lighting – LED Screw-in Lamps	38,341	21.7%
2	Interior Lighting - LED High-Bay Fixtures	17,291	9.8%
3	Interior Lighting - Occupancy Sensors	14,131	8.0%
4	Interior Lighting - Linear Lighting	10,192	5.8%
5	Retrocommissioning	9,326	5.3%
6	Exterior Lighting - LED Area Lighting	7,938	4.5%
7	Water Heating - Water Heater EF 2.0 - Heat Pump	6,247	3.5%
8	Cooling - Water-Cooled Chiller - COP 9.77 (0.36 kW/TR)	6,113	3.5%
9	Interior Fluorescent - Delamp and Install Reflectors	4,731	2.7%
10	Exterior Lighting - LED Screw-in Lamps	4,704	2.7%
11	Ventilation - Ventilation	4,586	2.6%
12	Office Equipment - Desktop Computer	4,568	2.6%
13	Chiller - Chilled Water Reset	4,340	2.5%
14	HVAC - Economizer	4,334	2.4%
15	Office Equipment - Server	4,019	2.3%
16	Cooling - Air-Cooled Chiller - COP 4.40 (EER 15.0)	3,907	2.2%
17	Ventilation - Demand Controlled	2,861	1.6%
18	Ventilation - Variable Speed Control	2,330	1.3%
19	RTU - Advanced Controls	2,111	1.2%
20	Refrigeration - High Efficiency Compressor	1,849	1.0%
	Total Top Measures	**153,922**	**87.0%**
	Total Cumulative savings in 2019	**176,999**	**100%**

[12] Includes 'Opt Outs' from both Indiana and Michigan

Table 8. Industrial Top Measures from Market Potential Study[13]

Rank	Industrial Measure	2019 Realistic Achievable Cumulative Savings (MWh)	% of Total
1	Interior Lighting – LED High-Bay Fixtures Lamps	13,133	22.7%
2	Pumping System - Variable Speed Drive	12,156	21.0%
3	Process - Timers and Controls	4,045	7.0%
4	Pumping System - System Optimization	3,815	6.6%
5	Interior Lighting – LED Screw-in Lamps	3,724	6.4%
6	Compressed Air - Variable Speed Drive	2,987	5.2%
7	HVAC - Economizer	2,249	3.9%
8	Compressed Air - Leak Management Program	1,973	3.4%
9	Exterior Lighting - LED Area Lighting Lamps	1,864	3.2%
10	Fan System - Flow Optimization	1,783	3.1%
11	Cooling - Water-Cooled Chiller - COP 9.77 (0.36 kW/TR)	1,137	2.0%
12	Destratification Fans (HVLS)	1,045	1.8%
13	Insulation - Wall Cavity	1,013	1.8%
14	Interior Lighting – Linear Lighting - T8 - F28 High Eff.	961	1.7%
15	Cooling - Air-Cooled Chiller - COP 4.40 (EER 15.0)	952	1.6%
16	Ventilation - Variable Speed Control	762	1.3%
17	Compressed Air - System Controls	698	1.2%
18	Chiller - Chilled Water Reset	629	1.1%
19	Interior Lighting - Occupancy Sensors	600	1.0%
20	Interior Fluorescent - Delamp and Install Reflectors	431	0.7%
	Total Top Measures	**55,956**	**96.8%**
	Total Cumulative savings in 2019	**57,809**	**100%**

From this information and recent I&M DSM activity, I&M has developed proxy EE bundles for residential, commercial and industrial customer classes to be modeled within Plexos®. What can be derived from the tables is that The Top 20 Measures comprise a large portion of all available EE potential. Additionally, potential was added from measures outside of the top 20 measures into a “miscellaneous” bundle for each sector. These miscellaneous bundles include the remaining cost effective measures identified in the MPS. These bundles are based on measure characteristics identified within the MPS and recent I&M DSM planning. Table 9 and Table 10 list the energy and cost profiles of EE resource “bundles” for the residential,

[13] Includes ‘Opt Outs’ from both Indiana and Michigan

commercial, and industrial sectors. The potential savings shown in, reflects the impact of "Opt Out" customers in both Indiana and Michigan.

Table 9. Incremental Residential Energy Efficiency (EE) Bundle Summary

Program	LCOE ($/MWh)	Installed Cost ($/kWh)	Yearly Potential Savings (MWh) 2020-2024	Yearly Potential Savings (MWh) 2025-2029	Yearly Potential Savings (MWh) 2030-2039	Yearly Potential Savings (MWh) 2040-2045
HVAC Equipment (AP)	$88.01	$0.60	8,759	10,256	11,790	12,346
HVAC Equipment (HAP)	$132.02	$0.90	1,777	1,956	1,799	1,770
Building Shell (AP)	$162.66	$1.65	1,516	1,623	1,786	1,834
Building Shell (HAP)	$243.99	$2.48	696	615	525	-
Appliances (AP)	$45.17	$0.26	4,520	4,720	4,969	5,087
Appliances (HAP)	$67.75	$0.40	2,238	2,004	1,689	1,627
Water Heating (AP)	$34.41	$0.24	6,340	7,232	6,226	5,295
Water Heating (HAP)	$51.62	$0.35	3,225	3,304	2,184	1,617
Lighting (AP)	$88.21	$0.64	-	-	1,954	1,866
Lighting (HAP)	$132.32	$0.97	-	-	592	1,029
Behavioral (AP)	$108.66	$0.10	28,500	28,500	28,500	28,500
Miscellaneous (AP)	$74.09	$0.54	2,694	3,549	3,175	3,614
Miscellaneous (AP)	$111.14	$0.81	919	786	977	1,184
Achievable Potential Sum			52,329	55,880	58,400	58,542
High Achievable Potential Sum			8,855	8,666	7,767	7,227

Table 10. Incremental Commercial & Industrial Energy Efficiency (EE) Bundle Summary

Program	LCOE ($/MWh)	Installed Cost ($/kWh)	Yearly Potential Savings (MWh) 2020-2024	Yearly Potential Savings (MWh) 2025-2029	Yearly Potential Savings (MWh) 2030-2039	Yearly Potential Savings (MWh) 2040-2045
VFD (AP)	$6.88	$0.06	5,411	5,748	6,484	6,629
VFD (HAP)	$10.31	$0.09	2,599	2,444	2,150	2,200
INDUSTRIAL MEASURES (AP)	$15.55	$0.11	6,417	5,688	4,636	4,361
INDUSTRIAL MEASURES (HAP)	$23.32	$0.16	2,624	2,003	1,190	999
HVAC & REFRIGERATION (AP)	$10.62	$0.10	10,216	9,875	9,757	9,625
HVAC & REFRIGERATION (HAP)	$15.93	$0.15	3,921	3,407	2,278	1,970
COMMERCIAL OUTDOOR LIGHTING (AP)	$11.89	$0.10	3,093	3,463	2,688	2,347
COMMERCIAL OUTDOOR LIGHTING (HAP)	$17.84	$0.15	1,109	1,388	906	738
COMMERCIAL INDOOR LIGHTING (AP)	$11.95	$0.10	20,482	22,707	19,885	17,912
COMMERCIAL INDOOR LIGHTING (HAP)	$17.93	$0.15	5,707	6,936	4,674	3,591
BUILDING MANAGEMENT SYSTEM (AP)	$28.25	$0.19	4,036	4,253	4,606	4,735
BUILDING MANAGEMENT SYSTEM (HAP)	$42.37	$0.29	1,770	1,608	1,380	1,325
COM Miscellaneous (AP)	$11.00	$0.10	12,149	16,004	14,315	16,295
COM Miscellaneous (HAP)	$16.50	$0.15	3,799	3,252	4,040	4,896
IND Miscellaneous (AP)	$15.55	$0.11	1,788	2,355	2,107	2,398
IND Miscellaneous (HAP)	$23.32	$0.16	602	515	640	776
Achievable Potential Sum			63,592	70,092	64,478	64,302
High Achievable Potential Sum			22,130	21,553	17,259	16,494

As can be seen from the tables, each program has both AP and HAP characteristics. The development of these characteristics is based on the work of AEG and feedback from I&M's DSM team. AEG further identified Realistic Achievable Potential (RAP) and Maximum Achievable Potential (MAP) factors to apply to measure savings. The RAP factor is utilized to develop the incremental AP program characteristics and the MAP factor is used to develop the incremental HAP program characteristics.

Tables 8 and 9 also show the Levelized Cost of Electricity (LCOE) and potential energy savings in 2020 for each of the bundles offered into the model as a potential resource. This provides a comparison of EE bundle cost versus potential savings. The model will determine if an EE bundle is beneficial to an optimization scenario. Each EE bundle is offered into the model as a stand-alone resource with its own unique cost and potential energy and demand savings. Should the model determine that a bundle is economical, that bundle will be included in the portfolio of optimized resources. To develop appropriate EE offerings to propose for I&M's customers, I&M will consider the details of each EE bundle that was optimized by the Plexos model and included in the Plan. Efforts to determine program attributes such as participant costs, penetration rates, and bill savings, prior to that point in time would be highly speculative and potentially inaccurate.

The corresponding cost effectiveness of the EE bundles are shown in Table 11. Table 11 details the Participant Cost Test (PCT), Ratepayer Impact Measure (RIM), Utility Cost Test (UCT) and Total Resource Cost (TRC) ratios for each of the bundles modeled. For the purpose of determining these ratios each bundle was assumed to be implemented in 2020 and in-service for its maximum life. Additionally, the cost effectiveness ratios used the same market cost as the IRP modeling and as discussed in Section 4.

Table 11. Energy Efficiency Cost Effectiveness Test Results

Program	Bundle Life	PCT Ratio	RIM Ratio	TRC Ratio	UCT Ratio
Residential Bundles					
HVAC Equipment (AP)	10	1.70	0.10	0.23	0.42
HVAC Equipment (HAP)	10	1.91	0.11	0.25	0.33
Building Shell (AP)	20	2.56	0.16	0.42	0.42
Building Shell (HAP)	20	3.05	0.13	0.36	0.29
Appliances (AP)	8	9.16	0.17	0.67	0.79
Appliances (HAP)	8	9.42	0.15	0.50	0.53
Water Heating (AP)	10	9.86	0.17	0.75	1.05
Water Heating (HAP)	10	9.93	0.16	0.56	0.70
Lighting (AP)	11	0.00	0.00	0.00	0.00
Lighting (HAP)	11	0.00	0.00	0.00	0.00
Behavioral (AP)	1	0.00	0.12	0.28	0.28
Miscellaneous (AP)	11	1.80	0.13	0.30	0.61
Miscellaneous (AP)	11	1.92	0.22	0.47	0.75
Commercial and Industrial Bundels					
VFD (AP)	14	2.03	0.14	0.42	5.25
VFD (HAP)	14	2.06	0.14	0.42	3.50
INDUSTRIAL MEASURES (AP)	10	12.99	0.20	2.09	2.36
INDUSTRIAL MEASURES (HAP)	10	13.42	0.19	1.85	1.57
HVAC & REFRIGERATION (AP)	17	7.17	0.23	1.74	4.42
HVAC & REFRIGERATION (HAP)	17	7.34	0.21	1.59	2.81
COMMERCIAL OUTDOOR LIGHTING (AP)	14	2.33	0.14	0.46	2.98
COMMERCIAL OUTDOOR LIGHTING (HAP)	14	2.39	0.14	0.45	1.99
COMMERCIAL INDOOR LIGHTING (AP)	13	3.10	0.18	0.70	3.39
COMMERCIAL INDOOR LIGHTING (HAP)	13	3.19	0.17	0.69	2.27
BUILDING MANAGEMENT SYSTEM (AP)	10	3.11	0.15	0.57	1.32
BUILDING MANAGEMENT SYSTEM (HAP)	10	3.28	0.15	0.54	0.88
COM Miscellaneous (AP)	16	4.73	0.19	1.05	3.79
COM Miscellaneous (HAP)	16	13.42	0.22	2.11	1.79
IND Miscellaneous (AP)	10	4.73	0.19	1.05	3.79
IND Miscellaneous (HAP)	10	13.42	0.22	2.11	1.79

4.4.3.2 Electric Energy Consumption Optimization (EECO) or Volt VAR Optimization (VVO) Modeled

Potential future VVO circuits considered for modeling varied in relative cost and energy-reduction effectiveness. The circuits were grouped into 15 "tranches" based on the relative potential peak demand and energy reduction of each tranche of circuits. The *Plexos*® model was able to pick the most cost-effective tranches first and add subsequent tranches as merited. Table 12 details all of the tranches offered into the model and the respective cost and performance of each. The costs shown are in 2017 dollars.

Table 12. EECO or Volt VAR Optimization (VVO) Tranche Profiles

Tranche	No. of Circuits	Capital Investment	Annual O&M	Demand Reduction (kW)	Energy Reduction (MWh)
1	32	$10,688,000	$320,640	8,066	33,211
2	32	$10,688,000	$320,640	6,443	26,529
3	33	$11,022,000	$330,660	6,185	25,464
4	33	$11,022,000	$330,660	5,701	23,473
5	33	$11,022,000	$330,660	5,413	22,286
6	33	$11,022,000	$330,660	5,115	21,058
7	33	$11,022,000	$330,660	4,793	19,734
8	33	$11,022,000	$330,660	4,574	18,834
9	33	$11,022,000	$330,660	4,397	18,101
10	33	$11,022,000	$330,660	4,223	17,386
11	33	$11,022,000	$330,660	4,004	16,484
12	33	$11,022,000	$330,660	3,668	15,100
13	33	$11,022,000	$330,660	3,264	13,439
14	32	$10,688,000	$320,640	2,549	10,494
15	32	$10,688,000	$320,640	1,733	7,137

4.4.3.3 Demand Response (DR) Modeled

Incremental levels of DR were included in the IRP model. These resources, which are included in the model as a resource for the entire operating company, were modeled based on the Bring Your Own Thermostat (BYOT) program for the Residential DR and an "EIS" light interface for the Commercial DR. In the BYOT program, customers would own and self-install Wi-Fi enabled thermostats, which will communicate with I&M. Table 13, below, shows the Residential DR resource offered into the model for residential customers. The model may select up to four units of both the Residential and Commercial resource, in any calendar year, beginning with 2020. Each unit has a service life of fifteen years. Table 13, shows the Commercial DR resource offered into the model for commercial customers.

Table 13. Residential Demand Response Resource

Sector	Participants	Demand Savings (kW)	Energy Savings (kWh)	Enrollment/ Installation Cost	Total First Year Cost	Ongoing Annual Cost	Service Life (Years)
Residential	3,375	3,299	837,540	$1,932,250	$1,971,408	$89,158	15

Table 14. Commercial Demand Response Resource

Sector	Participants	Demand Savings (kW)	Energy Savings (kWh)	Enrollment/ Installation Cost	Total First Year Cost	Ongoing Annual Cost	Service Life (Years)
Commercial	44	954	200,647	$468,963	$507,138	$214,524	15

4.4.3.4 Distributed Generation (DG) Evaluation

DG resources were evaluated assuming a residential rooftop solar resource, as this is the primary distributed resource. To determine the level of customer penetration I&M referenced a forecast conducted by IHS Inc. on behalf of PJM[14]. This forecast considered the level of solar photovoltaic (PV) installations over the period of 2019-2034. The updated forecast utilized by PJM included the Net Energy Metering Reform scenario[15]. Figure 23 below depicts the forecast of DG resources in I&M over the planning period. To determine the level of DG penetration I&M created a forecast using existing levels of DG, as well as the incremental additions from PJM's forecast. This forecast is shown as the red line in Figure 23 below. PJM's forecast issued in November 2018 represents a slightly lower level of DG penetration from the same forecast

[14] PJM solar forecast 2018: October 29, 2018. Available at https://pjm.com/-/media/committees-groups/subcommittees/las/20181127/20181127-item-06a-ihs-markit-pjm-solar-forecasts.ashx.

[15] Distributed Solar Generation Update, November 27, 2018. Available at https://pjm.com/-/media/committees-groups/subcommittees/las/20181127/20181127-item-06b-pjm-distributed-solar-generation-forecast.ashx and Distributed Solar Generation Forecast by Zone and State. Available at https://pjm.com/-/media/committees-groups/subcommittees/las/20181127/20181127-las-distributed-solar-generation-data.ashx.

issued one year prior. I&M intends to closely monitor the levels of DG installed throughout its service territory to observe any potential divergence from the forecast shown above.

It is significant to note that rooftop solar does not represent the most economic means for I&M to add renewable generation as the cost of rooftop solar remains considerably higher than the cost of large-scale solar which is discussed in Section 4.7.5.1.1.

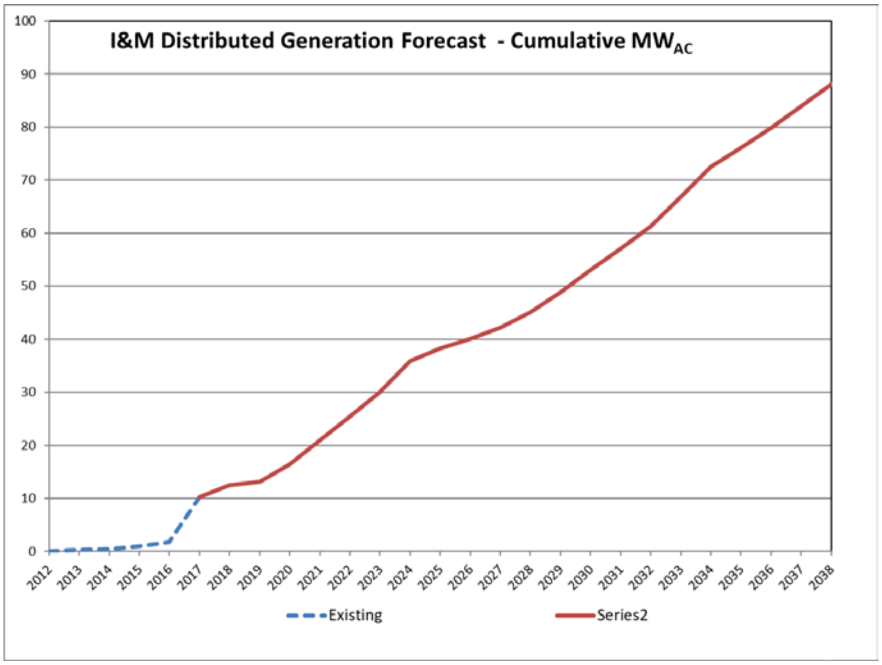

Figure 23. Cumulative Distributed Generation Additions/Projections for I&M

4.4.3.5 Optimizing Incremental Demand-side Resources

The *Plexos*® software views demand-side resources as non-dispatchable "generators" that produce energy similar to non-dispatchable supply-side generators such as wind or solar. Thus, the value of each resource is impacted by the hours of the day and time of the year that it "generates" energy.

4.4.3.6 Combined Heat and Power (CHP)

CHP (also known as Cogeneration) is a process where electricity is generated and the waste heat by-product is used for heating or other processes, raising the net thermal efficiency of the facility. To take advantage of the increased efficiency associated with CHP, the host must have a ready need for the heat that is otherwise potentially wasted in the generation of electricity.

I&M worked with AEP Generation Engineering to develop a generic CHP option. The CHP option developed is a 15MW facility utilizing a natural gas fired combustion turbine, Heat Recovery Steam Generator (HRSG) and SCR to control NO_x. A major assumption is that all of the steam is taken by the host and the efficiency of the modeled CHP resource is credited for the value of the steam provided to the host. The overnight installed cost is estimated to be $2,300/kW and the assumed modeled full load heat rate is approximately 4,800 Btu/kWh. Additionally, the assumed capacity factor was 90%.

4.5 Rate Design

Rate design changes warrant continued analyses. However, the characteristics of I&M's service territory must be factored into any rate design proposal. In general, the Company's approach to rate design changes is to include such proposals in its base rate proceedings in order to allow the parties, including staff and the commissions, to evaluate the reasonableness of such proposals.

4.6 Avoided Cost Discussion

4.6.1 Avoided Generation Capacity Cost

The avoided costs estimates utilized in this IRP are discussed in Section 4.6. The avoided generation capacity cost utilized in this analysis is shown in Figure 19.

4.6.2 Avoided Transmission Capacity Cost

Historically, the transmission and generation systems were expanded to meet substantial load growth. In more recent years, the demand forecast has been steadily declining to flat; however, transmission upgrades are still required to ensure continued reliability of the grid. Presently, the expansion and upgrades to the grid are driven primarily by a shift in the generation portfolio due to retirements and renewables integration, rehabilitation of aging grid infrastructure, changes in reliability standards, and direct service to new industrial demands.

The transmission system is planned, constructed, and operated to serve not only the load physically connected to the Company's wires but also to operate adequately and reliably with interconnected systems. The transmission system must have the capacity to reliably link generation resources with the various load centers and must be operated to provide this function even during forced and scheduled outages of critical transmission facilities. Conditions on neighboring systems and resulting parallel flows are other factors that also influence the capacity of the transmission system. Expansions of the transmission system are location specific and dependent upon the particular circumstances of load and connected generation at each location. The concept of transmission-related avoided cost is ever changing, based on the location being considered. Because transmission expansion is so dependent upon location and factors beyond the Company's control, such as generation from entities external to I&M and conditions on interconnected systems, it is nearly impossible to determine a transmission-related avoided cost that has real meaning or is reliable for the Company other than on a very narrow, site-specific, case-by-case basis.

4.6.3 Avoided Distribution Capacity Cost

The distribution system is designed, constructed, and operated to serve not only the load physically connected to I&M's wires, but coordinated for safe and reliable interface with generation resources and the transmission system as well.

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.

Because distribution system needs are so dependent upon location and factors beyond the Company's control, such as generation from others entities, local customer load changes, demand management, and local customer load diversity, it is nearly impossible to determine a global, aggregated distribution specific avoided cost that has real meaning or that is reliable for the Company to use in financial valuations other than on a very narrow, site specific, case-by-case basis.

4.6.4 Avoided Energy & Operating Cost

I&M's avoided operating cost including fuel, plant Operation & Maintenance (O&M), spinning reserve, and emission allowances, excluding transmission and distribution losses as discussed above, is provided in Figure 17 and Figure 18.

4.7 Identify and Screen Supply-side Resource Options

4.7.1 Capacity Resource Options

New construction supply-side alternatives were modeled to represent peaking and base-load/intermediate capacity resource options. To reduce the number of modeling permutations in *Plexos*®, the available technology options were limited to certain representative unit types. However, it is important to note that alternative technologies with comparable cost and performance characteristics may ultimately be substituted should technological or market-based profile changes warrant.

When applicable, I&M may take advantage of economic market capacity and energy opportunities. Prospectively, these opportunities could take the place of currently planned resources and will be evaluated on a case-by-case basis.

4.7.2 New Supply-side Capacity Alternatives

Natural gas base/intermediate and peaking generating technologies were considered in this IRP as well as large-scale solar and wind. Further details on these technologies are available in Exhibit D of the Appendix. To reduce the computational problem size within *Plexos*®, the number of alternatives explicitly modeled was reduced through an economic screening process which analyzed various supply options and developed a quantitative comparison for each duty-cycle type of capacity (i.e., base-load, intermediate, and peaking) on a forty year levelized basis. The options were screened by comparing levelized annual busbar costs over a range of capacity factors.

In this evaluation, each type of technology is represented by a line showing the relationship between its total levelized annual cost per kW and an assumed annual capacity factor. The value at a capacity factor of zero represents the fixed costs, including carrying charges and fixed Operations and Maintenance (O&M) costs, which would be incurred even if the unit produced no energy. The slope of the line reflects variable costs, including fuel, emissions, and variable O&M, which increase in proportion to the energy produced.

The best of class technology, for each duty cycle, determined by this screening process was explicitly modeled in *Plexos*®. These generation technologies were intended to represent reasonable proxies for each capacity type (base-load, intermediate, peaking). Subsequent substitution of specific technologies could occur in any later plan, based on emerging economic or non-economic factors not yet identified.

AEP continually tracks and monitors changes in the estimated cost and performance parameters for a wide array of generation technologies. Access to industry collaborative organizations such as EPRI and the Edison Electric Institute, AEP's association with architect and engineering firms and original equipment manufacturers, as well as its own experience and market intelligence, provides AEP with current estimates for the planning process. Table 15 offers a summary of the most recent technology performance parameter data developed. Additional parameters such as the quantities and rates of solid waste production, hazardous material consumption, and water consumption are significant; however, the options which passed the screening phase and were included in *Plexos*® were natural gas facilities which generally have limited impacts on these areas of concern.

Table 15. New Generation Technology Options with Key Assumptions

Type	Capability (MW) (d) Std. ISO	Summer	Winter	Installed Cost (c,e) ($/kW)	Capacity Factor (%)	LCOE (f) ($/MWh)
Base Load						
Nuclear	1,610	1,560	1,690	8,500	80	184.5
Pulv. Coal with Carbon Capture (PRB)	540	520	570	9,500	75	228.7
Combined Cycle (1X1 "J" Class)	610	800	820	900	75	60.4
Combined Cycle (2X1 "J" Class)	1,230	1,600	1,640	700	75	56.0
Combined Cycle (2X1 "H" Class)	1,150	1,490	1,530	700	75	56.9
Peaking						
Combustion Turbine (2 - "E" Class) (g)	180	190	190	1,200	25	151.7
Combustion Turbine (2 - "F" Class, w/evap coolers) (g)	490	500	510	700	25	118.4
Aero-Derivative (2 - Small Machines) (g)	120	120	120	1,100	25	138.7
Recip Engine Farm	220	220	230	1,300	25	130.6
Battery	10	10	10	1,900	25	161.3

4.7.3 Base/Intermediate Alternatives

Coal and Nuclear base-load options were evaluated by I&M but were not included in the *Plexos*® resource optimization modeling analyses. For coal generation resources, environmental regulation (see Section 3.3) makes the construction of new coal plants economically impractical. New nuclear construction is also economically impractical since it would potentially require an investment of $8,500/kW or more.

Intermediate generating sources are typically expected to serve a load-following and cycling duty and effectively shield base-load units from that obligation. Historically, many generators relied on older, smaller, less-efficient/higher dispatch cost, subcritical coal-fired or gas-steam units to serve such load-following roles. Over the last several years, these units have improved ramp rates and regulation capability, and reduced downturn (minimum load capabilities). With the anticipated retirement of I&M's coal and nuclear units, other generation dispatch alternatives and new generation will need to be considered to cost effectively meet these duty cycle's operating characteristics.

4.7.3.1 Natural Gas Combined Cycle (NGCC)

An NGCC plant combines a steam cycle and a combustion gas turbine cycle to produce power. Waste heat (~1,100°F) from one or more combustion turbines passes through a HRSG producing steam. The steam drives a steam turbine generator which produces about one-third of the NGCC plant power, depending upon the gas-to-steam turbine design "platform," while the combustion turbines produce the other two-thirds.

The main features of the NGCC plant are high reliability, reasonable capital costs, operating efficiency (at 45-63% Lower Heating Value), low emission levels, small footprint and shorter construction periods than coal-based plants. In the past 10 to 12 years, NGCC plants were often selected to meet new intermediate and certain base-load needs. Although cycling duty is typically not a concern, an issue faced by NGCC when load-following is the erosion of efficiency due to an inability to maintain optimum air-to-fuel pressure and turbine exhaust and steam temperatures. Methods to address these include:

- Installation of advanced automated controls.

- Supplemental firing while at full load with a reduction in firing when load decreases. When supplemental firing reaches zero, fuel to the gas turbine is cutback. This approach would reduce efficiency at full load, but would likewise greatly reduce efficiency degradation in lower-load ranges.
- Use of multiple gas turbines coupled with a waste heat boiler that will give the widest load range with minimum efficiency penalty.

At this time, the Company considers both "1x1" and "2x1" 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

4.7.4 Peaking Alternatives

Peaking generating sources provide needed capacity during high-use peaking periods and/or periods in which significant shifts in the load (or supply) curve dictate the need for "quick-response" capability. The peaks occur for only a few hours each year and the installed reserve requirement is predicated on a one day in ten-year loss of load expectation, so the capacity dedicated to serving this reliability function can be expected to provide relatively little energy over an annual load cycle. As a result, fuel efficiency and other variable costs applicable to these resources are of lesser concern. Rather, this capacity should be obtained at the lowest practical installed/fixed cost, despite the fact that such capacity often has very high energy costs. Ultimately, such "peaking" resource requirements are manifested in the system load duration curve.

In addition, in certain situations, peaking capacity such as combustion turbines can provide backup and some have the ability to provide emergency, Black Start, capability to the grid.

4.7.4.1 Simple Cycle Combustion Turbines (NGCT)

In "industrial" or "frame-type" Combustion Turbine (CT) systems, air compressed by an axial compressor is mixed with fuel and burned in a combustion chamber. The resulting hot gas then expands and cools while passing through a turbine. The rotating rear turbine not only runs the axial compressor in the front section but also provides rotating shaft power to drive an electric generator. The exhaust from a combustion turbine can range in temperature between 800 and 1,150 degrees Fahrenheit and contains substantial thermal energy. A CT system is one in which the exhaust from the gas turbine is vented to the atmosphere and its energy lost, *i.e.*, not recovered as in a combined-cycle design. While not as efficient (at 30-35% Lower Heating Value), they are inexpensive to purchase, compact, and simple to operate.

4.7.4.2 Aeroderivatives (AD)

Aeroderivatives (AD) are aircraft jet engines used in ground installations for power generation. They are smaller in size, lighter weight, and can start and stop quicker than their larger industrial or "frame" counterparts. For example, the GE 7E frame machine requires 20 to 30 minutes to ramp up to full load while the smaller LM6000 aeroderivative only needs 10 minutes from start to full load. However, the cost per kW of an aeroderivative is considerably higher than a frame machine.

The AD performance operating characteristics of rapid startup and shutdown make the aeroderivatives well suited to peaking generation needs. ADs can operate at full load for a small percentage of the time allowing for multiple daily startups to meet peak demands, compared to frame machines which are more commonly expected to start up once per day and operate at continuous full load for 10 to 16 hours per day. The cycling capabilities provide ADs the ability to backup variable renewables such as solar and wind. This operating characteristic is expected to become more valuable over time as: A) the penetration of variable renewables increases; B) base-load generation processes become more complex limiting their ability to load-follow and; C) more intermediate coal-fueled generating units are retired from commercial service.

AD units weigh less than their industrial counterparts allowing for skid or modular installations. Efficiency is also a consideration in choosing an AD over an industrial turbine. AD units in the less than 100MW range are more efficient and have lower heat rates in simple cycle operation than industrial units of equivalent size. Exhaust gas temperatures are lower in AD units.

4.7.4.3 Reciprocating Engines (RE)

The use of Reciprocating Engines (RE) or internal combustion engines has increased over the last twenty years. According to EPRI, in 1993 about 5% of the total RE units sold were natural gas-fired spark ignition engines and post 2000 sales of natural gas-fired generators have remained above 10% of total units sold worldwide.

Improvements in emission control systems and thermal efficiency have led to the increased utilization of natural gas-fired RE generators incorporated into multi-unit power generation stations for main grid applications. RE generators' high efficiency, flat heat rate curves and rapid response make this technology very well suited for peaking and intermediate load service and as back up to intermittent generating resources. Compared to AD units, RE generators generally have shorter start-time durations. Additionally, the fuel supply pressure required is in the range of 40 to 85 psig; this lower gas pressure gives this technology more flexibility when identifying locations. A further advantage of RE generators is that power output is less affected by increasing elevation and ambient temperature as compared to gas turbine technology. Also, a RE plant generally would consist of multiple units, which will be more efficient at part load operation than a single gas turbine unit of equivalent size because of the ability to shut down units and to operate the remaining units at higher load. Common RE unit sizes have generally ranged from 8MW to 18MW per machine with heat rates in the range of 8,100 –to- 8,600 Btu/kWh (Higher Heating Value).

Regarding operating cost, RE generators have a somewhat greater variable O&M than a comparable gas turbine; however, over the long term, maintenance costs of RE are generally lower because the operating hours between major maintenance can be twice as long as gas turbines of similar size.

4.7.4.4 Battery Storage

The modeling of Battery Storage as a Peaking resource option is becoming a more common occurrence in IRPs. In recent years Lithium-ion battery technology has emerged as the fastest growing platform for stationary storage applications. The Battery Storage resource that was modeled in this IRP is a Lithium-ion storage technology and it has a nameplate rating of 10MW and 40MWh, with a round trip efficiency of 83%. See Figure 24 for the forecasted installed cost of this resource. To develop this resource, AEP's Generation Engineering Services considered a wide range of sources including: the DOE/EPRI 2015 Electricity Storage Handbook in Collaboration with the National Rural Electric Cooperative Association (NRECA), EPRI, BNEF and battery storage equipment suppliers. The storage resource characteristics and cost were updated in early 2019.

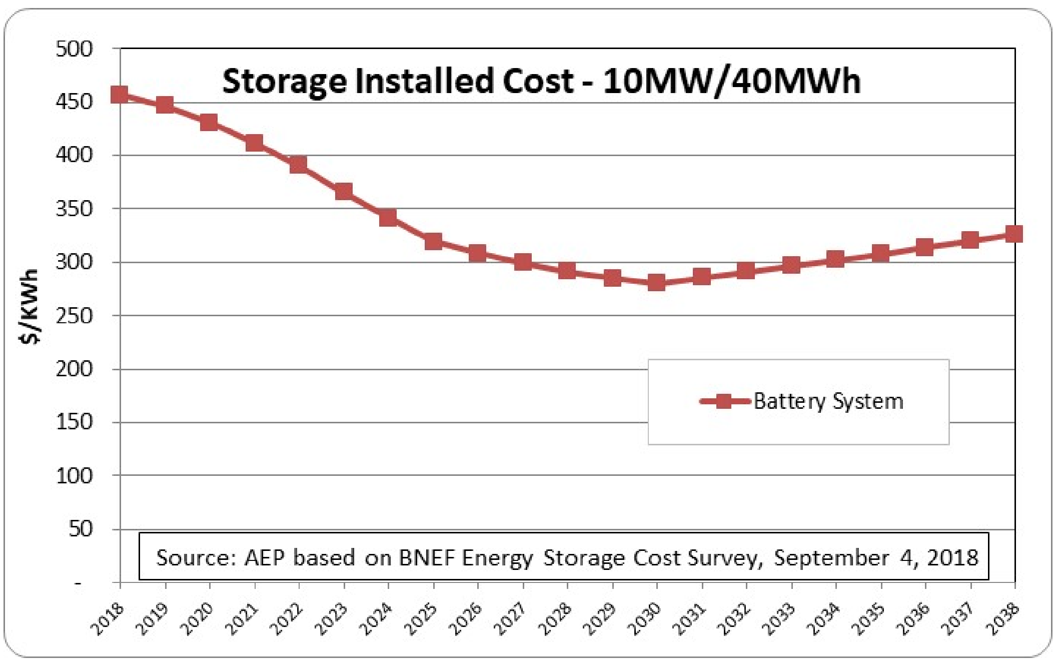

Figure 24. Energy Storage Installed Cost

4.7.5 Short-Term Market Purchase (STMP)

Short-Term Market Purchase (STMP) alternative resources were made available to the model for selection during the development of the optimal plans. This resource is assumed to have no energy associated with it, a contract term of one year and 1,000MW can be added annually. The pricing of these purchases is based on the PJM Capacity Prices shown in Figure

19. The purpose of adding this resource was to allow the model an option to include a short-term capacity commitment as opposed to building a long-term capacity resource.

4.7.6 Renewable Alternatives

Renewable generation alternatives use energy sources that are either naturally occurring (wind, solar, hydro or geothermal), or are sourced from a by-product or waste-product of another process (biomass or landfill gas). In the past, on a national level development of these resources has been driven primarily as the result of renewable portfolio requirements. That is not universally true now as advancements in both solar photovoltaics and wind turbine manufacturing have reduced both installed and ongoing costs.

At this time within the industry, renewable energy resources, because of their intermittent nature, provide more energy value than capacity value. For this IRP, the overall threshold for intermittent resource additions are 30% of I&M's energy demand for wind and 15% for solar. This assumes that the RTO and other key stakeholders will advance the understanding, forecasting and management of intermittent resources, ultimately supporting a higher penetration level and capacity planning values.

4.7.6.1 Solar

4.7.6.1.1 Large-Scale Solar

Solar power comes in two forms to produce electricity: concentrating and photovoltaics. Concentrating solar — which heats a working fluid to temperatures sufficient to generate steam to power a turbine — produces electricity on a large scale and is similar to traditional centralized supply assets in that respect. Photovoltaics can more easily be distributed throughout the grid and are a scalable resource that, for example, can be as small as a few kilowatts or as large as 500MW. This IRP assumes its solar resources will be photovoltaic.

The cost of large-, or utility-scale, solar projects has declined in recent years and is expected to continue to decline through 2023 (see Figure 25). This has been mostly a result of reduced panel prices that have resulted from manufacturing efficiencies spurred by accelerating penetration of solar energy in Europe, Japan, and California. With the trend firmly established, forecasts generally foresee declining nominal prices in the next decade as well, notwithstanding solar panel tariffs which from an IRP perspective are regarded as a short-term impact.

Large-scale solar plants require less lead time to build than fossil plants. There is no defined limit for how much utility solar can be built in a given time. However, in practice, solar facilities are not added without considering the timing impacts of obtaining siting and regulatory approval, for example.

Solar resources were made available in the *Plexos* model with some limits on the rate with which they could be chosen. In the IRP modeling, the assumption was made that large-scale solar resources were available in yearly quantities up to 300MWac[16] of nameplate capacity starting in 2022. A limit on solar capacity additions is needed because as solar costs continue to decrease relative to the market price of energy, there will come a point where the optimization model will theoretically pick an unlimited amount of solar resources, a nonsensical result. Additionally, this 300MWac annual threshold recognizes that there is a practical limit as to the number of sites that can be identified, permitted, constructed, and interconnected by I&M in a given year. For example, the land requirement to develop a 1MW solar plant is estimated to be 7 acres, implying that 700 acres of land would be required to develop 100MW of solar annually. Over the planning period the maximum threshold for solar resource additions was limited to approximately 15% of I&M's load obligation or 1,700MW. Certainly, as I&M gains experience with solar installations, this limit would likely be modified (for example, it may be lower earlier and greater later).

Solar resources were available in two tiers. Tier 2 as referred to in this IRP, is the overall pricing trend over the planning period based on the BNEF utility scale solar pricing forecast. An additional pricing tier was developed, tier 1, which is 10% lower than the base BNEF forecast. The tier 1 pricing is considered a "Best-In-Class" solar resource. The 10% discount from the tier 2 product is based on the concept that during an RFP process the "Best Bids" would be approximately 10% less than the average bids. Both tiers of solar resources were available in

[16] Manufacturers usually quote system performance in DC watts; however electric service from the utility is supplied in AC watts. An inverter converts the DC electrical current into AC electrical current. Depending on the inverter efficiency, the AC wattage may be anywhere from 80 to 95 percent of the DC wattage.

blocks of 150MW, which is comprised of three 50MW installations and totals 300MW annually. Additionally, both tiers of solar resources were modeled with capacity factors of approximately 24.4%, which is representative of a tracking solar resource located in Ft. Wayne, Indiana.

Figure 25 illustrates the projected large-scale solar pricing included in the IRP model. Both tiers account for Federal ITCs. The large-scale solar pricing used in this IRP reflects a normalized treatment of the ITC, as well as a four-year safe harbor factor in ITC pricing. This safe harbor factor allows projects to lock in ITC benefits four years prior to commercial operation, as long as construction has been commenced. The ITC benefit is included through 2030. After 2030, the 10% ITC benefit would become indiscernible from potential variations in forecasted prices. Solar resources are modeled with a 51.1% capacity credit, which is based on PJM's expected long-term performance of the resource.

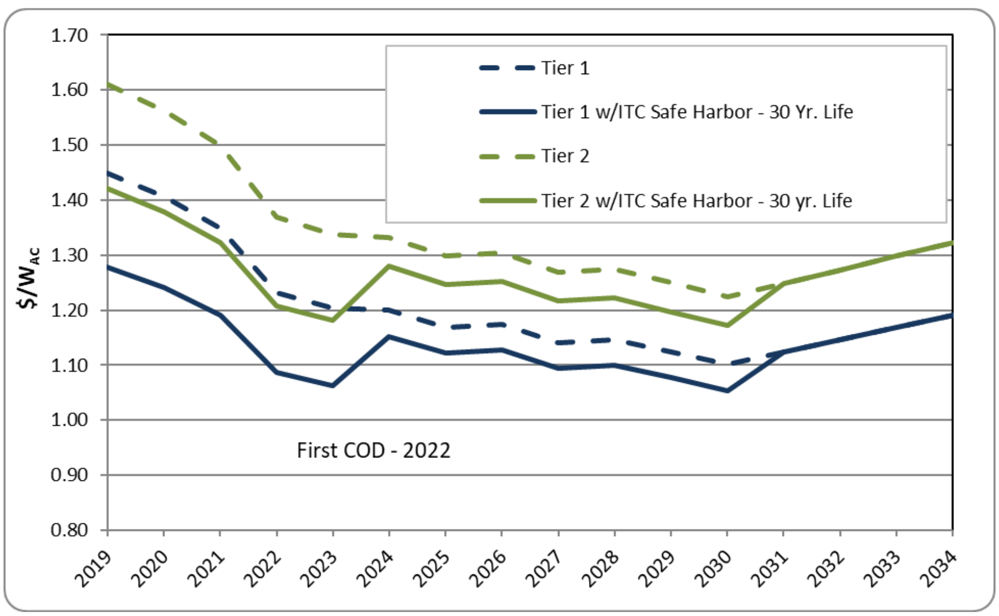

Figure 25. Large-Scale Solar Pricing Tiers

4.7.6.1.2 Trends in Solar Energy Pricing

As mentioned above, solar energy prices have declined significantly in recent years as shown below in Figure 26. From 2010 to 2018 installation costs have declined by more than 60% for residential, commercial, and large-scale solar. Further, large-scale solar has been, and is projected to be, substantially lower in cost compared to other sectors, with large-scale installations costing 49% and 29% less than residential and commercial installations, respectively, based on 2019 costs.

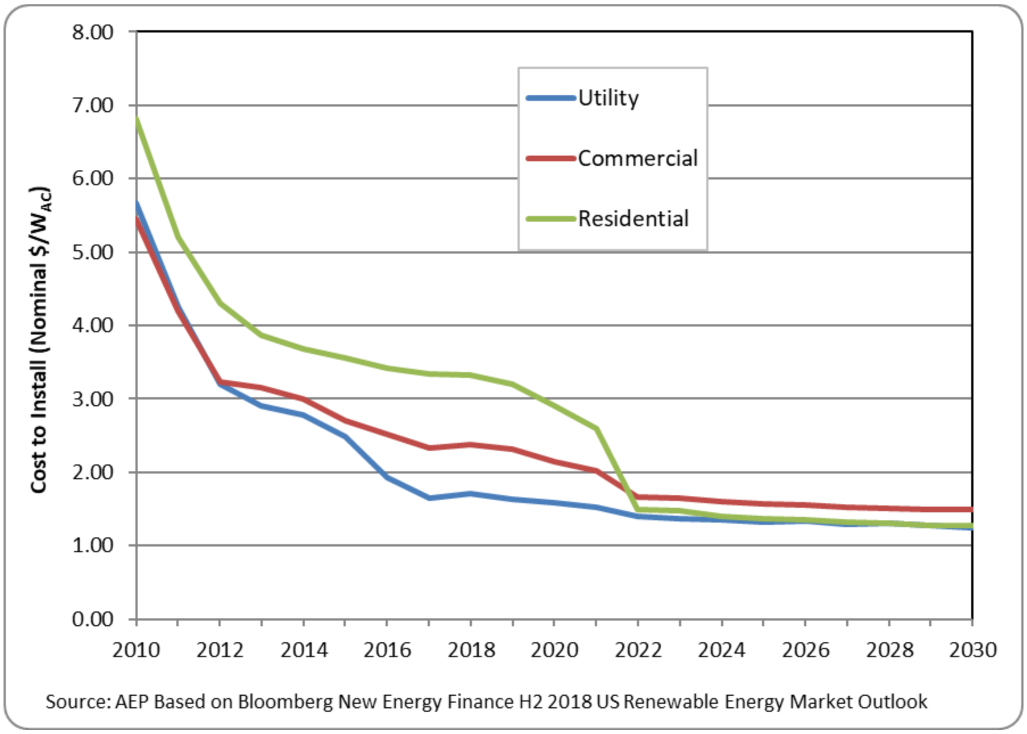

Figure 26. PJM Photovoltaic (PV) Installation Cost (Nominal $/W$_{AC}$) Trends, excluding Investment Tax Credit Benefits

4.7.6.2 Wind

Large-scale wind energy is generated by turbines ranging from 1.0 to 3.2MW. Typically, multiple wind turbines are grouped in rows or grids to develop a wind turbine power project which requires only a single connection to the transmission system. Location of wind turbines at the proper site is particularly critical as not only does the wind resource vary by geography, but also its proximity to a transmission system with available capacity, which will factor into the cost.

A variable source of power in most non-coastal locales, with capacity factors ranging from 30 percent (in the eastern portion of the U.S.) to over 50 percent (largely in more westerly portions of the U.S., including the Plains states), wind energy's life-cycle cost ($/MWh), excluding subsidies, is currently higher than the marginal (avoided) cost of energy, in spite of its negligible operating costs.

Another consideration with wind power is that its most critical factors (*i.e.*, wind speed and sustainability) are typically highest in more remote locations, which forces the electricity to be transmitted longer distances to load centers necessitating the build out of EHV transmission to optimally integrate large additions of wind into the grid.

For modeling purposes, wind resources are first made available to the model in 2022 (i.e., commercial operation date 12/31/21), due to the amount of time necessary to secure resources and obtain any necessary regulatory approvals. Figure 27 shows the LCOE prices of one wind resource tranches assumed for the IRP. The first tranche of wind resources, Tranche A, was modeled as a 150MW resource block with a 40.5% capacity factor load shape. The second tranche of wind resources, Tranche B, was modeled as a 150MW resource block with a 35% capacity factor load shape. Wind resources capacity credit for capacity planning purposes is based on PJM's analysis and is assumed to be 12.3% of nameplate[17]. The wind pricing reflects the value of Federal Production Tax Credits (PTCs). After 2020 tax credits reduce to 80%, 60% and 40% of their 2020 value in 2021, 2022, and 2023, respectively. These PTC values are based on developers taking advantage of the safe-harbor guidelines which provide up to a four-year delay in the effects of declining tax credits as long as adequate construction has commenced. Wind prices were developed based on the Bloomberg New Energy Finance H2 2018 U.S. Renewable Energy Market Outlook and market knowledge.

The amount of wind resources available beginning in 2022 was limited to 300MW nameplate annually through the remainder of the planning period. In total, wind resources were limited to 2,100MW nameplate over the planning period. The annual limit on wind additions is based on I&M's ability to plan, manage and develop either the construction or the procurement of these resources. As with solar resource additions, as I&M gains experience with wind installations, this limit would likely be modified (for example, it may be lower earlier and greater later). This cap is based on the DOE's Wind Vision Report[18] which suggests from numerous

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[17] PJM "Effective Load Carrying Capability (ELCC) Analysis for Wind and Solar Resources", February 7, 2019.

[18] *Wind Vision: A New Era for Wind Power in the United States* (2015). Retrieved from http://www1.eere.energy.gov/library/default.aspx?Page=12, Figure 1-5.

transmission studies that transmission grids should be able to support 20% to 30% of intermittent resources in the 2020 to 2030 timeframe. The cap for I&M allows the model to select up to 30% of generation energy resources as wind-powered by 2038.

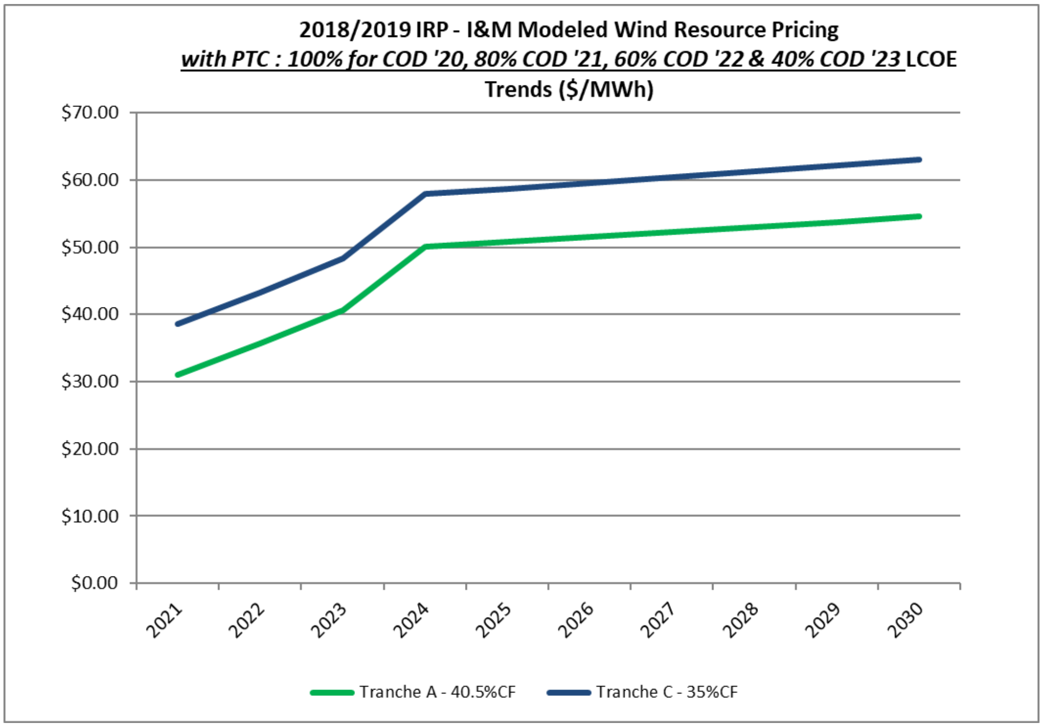

Figure 27. Levelized Cost of Electricity of Wind Resources (Nominal $/MWh)

4.7.6.3 Hydro

The available sources of, particularly, larger hydroelectric potential have largely been exploited and those that remain must compete with the other uses, including recreation and navigation. The potentially lengthy time associated with environmental studies, Federal Army Corp of Engineer permitting, high up-front construction costs, and environmental issues (fish and wildlife) make new hydro prohibitive at this time. As such, no incremental hydroelectric resources were considered in this IRP.

4.7.6.4 Biomass

Biomass is a term that typically includes organic waste products (sawdust or other wood waste), organic crops (corn, switch grass, poplar trees, willow trees, etc.), or biogas produced from organic materials, as well as select other materials. Biomass costs will vary significantly depending upon the feedstock. Biomass is typically used in power generation to fuel a steam generator (boiler) that subsequently drives a steam turbine generator; similar to the same process of many traditional coal fired generation units. Some biomass generation facilities use biomass as the primary fuel, however, there are some existing coal-fired generating stations that will use biomass as a blend with the coal. Given these factors, plus the typical high cost and required feedstock supply and attendant long-term pricing issues, no incremental biomass resources were considered in this IRP.

4.8 Integration of Supply-Side and Demand-Side Options within *Plexos*® Modeling

Each supply-side and demand-side resource is offered into the *Plexos*® model on an equivalent basis. Each resource has specific values for capacity, energy production (or savings), and cost. The *Plexos*® model selects resources in order to reduce the overall portfolio cost, regardless of whether the resource is on the supply- or demand-side, and regardless of whether or not there is an absolute capacity need. In other words, the model selects resources that lower costs to customers.

4.8.1 Optimization of Expanded DSM Programs

As described in Section 4.4, EE, DR and EECO options that would be incremental to the current programs were modeled as resources within *Plexos*®. In this regard, they are “demand-side power plants” that produce energy according to their end use load shape. They have an initial (program) cost with *no* subsequent annual operating costs. Likewise, they are “retired” at the end of their useful (EE measure) lives.

4.8.2 Optimization of Other Demand-Side Resources

Customer-sited DG, specifically rooftop solar, was not modeled. Instead, reductions in energy use and peak demand were included as a resource based on the adoption rates. CHP was modeled as a high thermal efficiency NGCC facility.

4.9 Summary of Resources Considered

Table 16 summarizes all of the resources considered within this IRP as well as identifies the resources that were included in the modeling for this IRP.

Table 16. Resource Screening Analysis Summary

Resource	Selected for Further IRP Analysis	Report Location Describing Evaluation/Screening Analysis
Aeroderivative	Yes	4.5.4.1
Battery Storage	Yes	4.5.4.4
Biomass	No	4.5.5.4
Coal-Fired Generation	No	4.5.3
Combined Heat and Power	Yes	4.4.3.6
Demand Response	Yes	4.4.3.3
Distributed Generation	Yes	4.4.3.4
Energy Efficiency	Yes	4.4.3.1
Hydros	No	4.5.5.3
Natural Gas Combined Cycle	Yes	4.5.3.1
Nuclear Generation	No	4.5.3
Rate Design	No	4.4.4
Reciprocating Engines	Yes	4.5.4.3
Simple Cycle Combustion Turbine	Yes	4.5.4.1
Short-Term Market Purchase	Yes	4.7.5
Solar	Yes	4.5.5.1
Transmission Facilities	No	3.5
Electric Energy Consumption Optimization	Yes	4.4.3.2
Wind	Yes	4.5.5.2

Figure 28 shows the results of the resource screening of the supply-side resources. The figure shows the supply-side resource configurations included in the model.

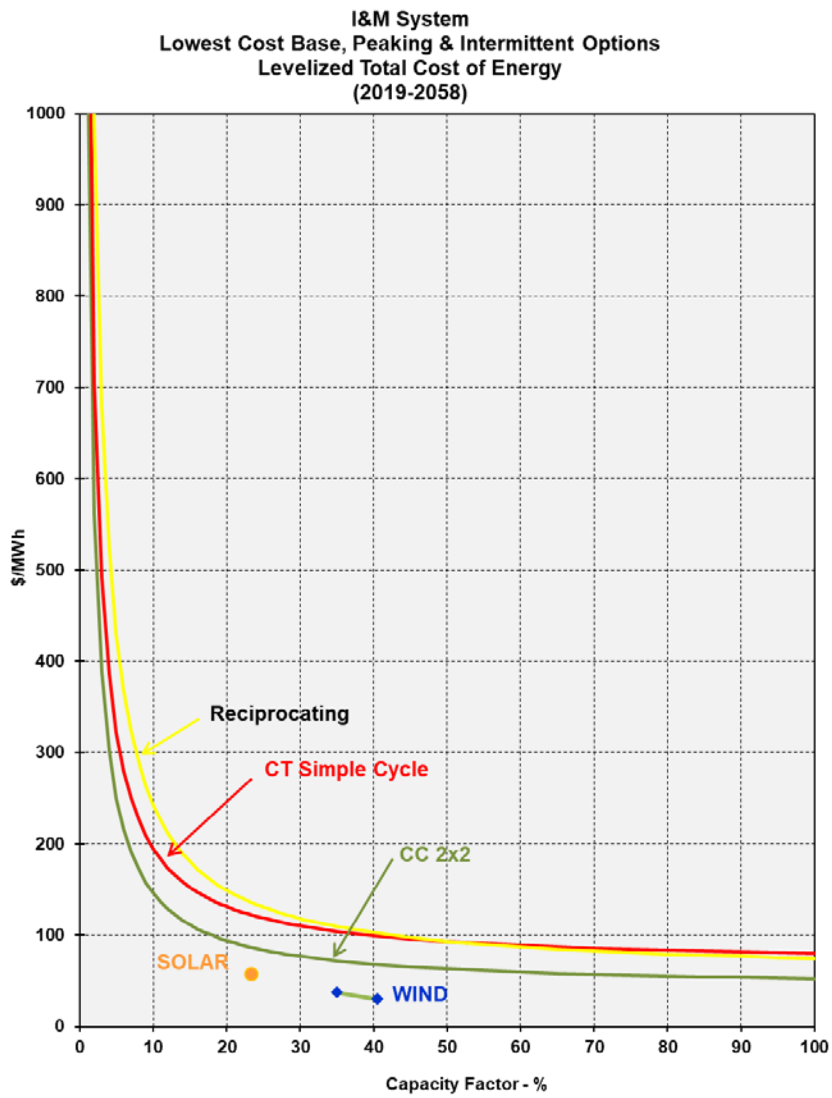

Figure 28. I&M Supply-Side Resource Screening Results

5.0 Resource Portfolio Modeling

5.1 The *Plexos*® Model - An Overview

Plexos® LP long-term optimization model, also known as “LT Plan®,” served as the basis from which the I&M capacity requirement evaluations were examined and recommendations were made. The LT Plan® model finds the optimal portfolio of future capacity and energy resources, including DSM additions, which minimizes the cumulative present worth (CPW) of a planning entity’s generation-related variable and fixed costs over a long-term planning horizon. By minimizing CPW the model will provide optimized portfolios with the lowest customer rates, while adhering to the Company’s constraints. Low, stable rates benefit the entire region by attracting new commercial and industrial customers, and retaining/expanding existing load.

The LT Plan® model uses an objective function which seeks to minimize the aggregate of the following capital and production-related (energy) costs of the portfolio of resources:

- Fixed costs of capacity additions, *i.e.*, carrying charges on incremental capacity additions (based on an I&M-specific, weighted average cost of capital), and fixed O&M;
- fixed costs of any capacity purchases;
- program costs of (incremental) DSM alternatives;
- variable costs associated with I&M generating units. This includes fuel, start-up, consumables, market replacement cost of emission allowances and/or carbon ‘tax,’ and variable O&M costs;
- distributed, or customer-domiciled, resources which were effectively valued at the equivalent of a full-retail “net metering” credit to those customers; and
- a ‘netting’ of the production revenue earned in the PJM power market from I&M’s generation resource sales *and* the <u>cost</u> of energy – based on unique load shapes from PJM purchases necessary to meet I&M’s load obligation.

The LT Plan® model executes the objective function described above while abiding by the following possible constraints:

- Minimum and maximum reserve margins;

- resource additions (i.e., maximum units built);
- age and lifetime of power generation facilities;
- retrofit dependencies (SCR and FGD combinations);
- operation constraints such as ramp rates, minimum up/down times, capacity, heat rates, etc.;
- fuel burn minimum and maximums;
- emission limits on effluents such as SO_2 and NO_x; and
- energy contract parameters such as energy and capacity.

The model inputs that comprise the objective function and constraints are considered in the development of an integrated plan that best fits the utility system being analyzed. LT Plan® does not develop a full regulatory Cost-of-Service profile. Rather, it typically considers only the relative load and generation costs that changes from plan-to-plan, and not fixed "embedded" costs associated with existing generating capacity and demand-side programs that would remain constant under any scenario. Likewise, transmission costs are included only to the extent that they are associated with new generating capacity, or are linked to specific supply alternatives. In other words, generic (nondescript or non-site-specific) capacity resource modeling would typically not incorporate significant capital expenditures for transmission interconnection costs.

5.1.1 Key Input Parameters

Two of the major underpinnings in this IRP are long-term forecasts of I&M's energy requirements and peak demand, as well as the price of various generation-related commodities, including energy, capacity, coal, natural gas and, potentially, CO_2/carbon. AEP created both forecasts internally. The AEP Economic Forecasting organization created the load forecast, while the AEP Fundamental Analysis group created the long-term commodity-pricing forecast. These groups have many years of experience forecasting I&M and AEP system-wide demand and energy requirements and fundamental pricing for both internal operational and regulatory purposes. Moreover, the Fundamental Analysis group constantly performs peer review by way of comparing and contrasting its commodity pricing projections versus "consensus" pricing on the part of outside forecasting entities such as IHS- Cambridge Energy Research Associates (CERA), Petroleum Industry Research Associates (PIRA) and the EIA.

Another input parameter of note is the PJM capacity reserve margin. The PJM capacity reserve margin, combined with I&M's forecasted demand, set the limit for the minimum capacity required to maintain service reliability within the region. Each of the scenarios modeled below are optimized while adhering to this constraint. This ensures that each of the scenarios considered will result in an acceptable amount of generation available to I&M customers.

With regard to environmental regulations, the estimated, potential impact of current and pending regulations was factored into the analyses of potential resource plans by adding incremental costs to comply.

Additional critical input parameters include the installed cost of replacement capacity alternative options, as well as the attendant operating costs associated with those options. This data came from the AEP Engineering Services organization.

5.2 *Plexos*® Optimization

5.2.1 Modeling Options and Constraints

The major system parameters that were modeled are detailed below. The *Plexos* LT Plan® models these parameters in tandem with the objective function in order to yield the least-cost resource plan.

There are many variants of available supply-side and demand-side resource options and types. As a practical limitation, not all known resource types are made available as modeling options. A screening of available supply-side technologies was performed with the optimum assets made subsequently available as options. Such screens for supply alternatives were performed for baseload, intermediate, and peaking duty cycles.

The selected technology alternatives from this screening process do not necessarily represent the optimum technology choice for that duty-cycle family. Rather, they reflect proxies for modeling purposes. Other factors which will determine the ultimate technology type (e.g., choices for peaking technologies) are taken into consideration. The full list of screened supply options is included in Exhibit D of the Appendix.

Based on the established comparative economic screenings, the following specific supply alternatives were modeled in *Plexos*® for each designated duty cycle:

- *Peaking* capacity was modeled, effective in 2022 due to the anticipated period required to approve, site, engineer and construct, from:
    - A 50% share of two CT units consisting of "F" class turbines with evaporative coolers rated at 500MW total at summer conditions.
    - AD units consisting of 2 aeroderivative turbines at 120MW total at summer conditions.
    - RICE units consisting of 12 reciprocating engines rated at 220MW total at summer conditions and a single engine configuration rated at 18MW summer conditions as a proxy for a Mini/Micro Grid resource.
    - Battery Storage units available in 10MW blocks per year.
- *Intermediate-Baseload* capacity was modeled, effective in 2023 due to anticipated period required to approve, site, engineer and construct, from:
    - A 25% share of a NGCC (2x1 "J" class turbines with duct firing and evaporative inlet air cooling) facility, rated at 1,600MW at summer conditions. The 25% interest assumes I&M coordinates the addition of this resource with other parties.
- Wind resources were made available up to 300MW annually beginning in 2022 (commercial operation date 12/31/21). One 150MW unit of each Tranche A and B was available each year. Tranche A had a LCOE of $31.05/MWh, in 2022 with the PTC. Tranche B had a LCOE of $38.55/MWh, in 2022 with the PTC. Wind resources were assumed to have a PJM capacity value equal to 12.3% of nameplate rating. Further discussion of Wind resource assumptions can be found in Section 4.5.5.2.
- Large-scale solar resources were made available in two tiers, with up to 150MW of each tier available each year beginning in 2022, for a total of up to 300MW annually. Initial costs for Tier 1 were approximately $50.00/MWh in 2022 with the ITC. Tier 2 has an initial cost of approximately $54.00/MWh in 2022 with the ITC. Solar resources were assumed to have a PJM capacity

value equal to 51.1% of nameplate rating. Further discussion of Large Scale Solar resource assumptions can be found in Section 4.5.5.1.1.

- Short-Term Market Purchase (STMP) alternative resources were made available to the model for selection during the development of the optimal plans. This resource is assumed to have no energy associated with it, a contract term of one year and 1,000MW can be added annually. The pricing of these purchases is based on the PJM Capacity Prices shown in Figure 19. The purpose of adding this resource was to allow the model an option to include a short-term commitment as opposed to building a long-term resource.
- DG, in the form of distributed solar resources, was embedded in amounts equal to a CAGR of 10.3% over the planning period.
- CHP resources were made available in 15MW (nameplate) 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.
- EE resources—incremental to those already incorporated into the Company's long-term load and peak demand forecast in up to 29 unique "bundles" of Residential, Commercial, and Industrial measures considering cost and performance parameters for both HAP and AP categories are available in 2020.
- DR resources were made available for Residential and Commercial customers in 2020.
- EECO was available in 2020 and 15 tranches of varying installed costs and number of circuits/sizes ranging from a low of 1.7MW up to 8.1MW of demand savings potential.

5.2.2 Optimized Portfolios

The key decision I&M makes, with stakeholder input, during the planning period is how to fill the resource need identified. Portfolios with various options addressing I&M's capacity and energy resource needs over time were optimized under various commodity price and load conditions. In order to test I&M's resource selection across varying commodity price and load conditions, twenty four (24) scenarios were analyzed for this IRP (see Table 17). The scenarios are intended to evaluate a wide-range of future potential outcomes, and in some cases stretch the evaluation beyond what the Company believes are reasonable boundaries. The resource portfolios discussed below for these scenarios represent incremental resources, which are in addition to those currently in-service or under development. The output tables from each model run for the 'Optimized Portfolios' in Table 17 are included in Exhibit C of the Appendix.

Table 17. Optimized Portfolios

	Type	Name	Commodity Pricing Conditions	Load Conditions
Group 1	**Group 1** Commodity Pricing Scenarios	1. Base - (RP1 Retires 12/2028; RP2 Lease Expires 12/2022)	Base	Base
		2. High Band - (RP1 Retires 12/2028; RP2 Lease Expires 12/2022)	High Band	Base
		3. Low Band - (RP1 Retires 12/2028; RP2 Lease Expires 12/2022)	Low Band	Base
		4. No Carbon - (RP1 Retires 12/2028; RP2 Lease Expires 12/2022)	No Carbon	Base
Group 2	**Group 2 & 2A** Rockport Scenarios Includes Storage & MiniGrid	5. Case 5 & 5A (RP1 Retires 12/2028; RP2 Lease Expires 12/2022)	Base/No Carbon (A)	Base
		6. Case 6 & 6A (RP1 FGD 1/2026 & Retires 12/2044; RP2 Lease Expires 12/2022)	Base/No Carbon (A)	Base
		7. Case 7 & 7A (RP1 FGD 1/2029 & Retires 12/2044; RP2 Lease Expires 12/2022)	Base/No Carbon (A)	Base
		8. Case 8 &8A (RP1 Retires 1/2025; RP2 Lease Extended, FGD 1/2029, & Retires 12/2048)	Base/No Carbon (A)	Base
Group 3	**Group 3** IRP Scenarios Includes Storage & MiniGrid	**9. Transitional** (RP2 Lease End 2022, RP1 Retire 12/2028)	Base	Base
		10. 12 - Year Peaking (Post RP2 Lease End)	Base	Base
		11. 15 - Year Peaking (Post RP2 Lease End)	Base	Base
		12. Case 12 & 12a 12 - High Renewables - Peaking 12a - High Renewables - Peaking and CC	Base	Base
Group 4	**Group 4** Load Scenarios	**13. Low Load**	Base	Low
		14. High Load	Base	High
		15. Low Load	Low Band	Low
		16. High Load	High Band	High
Group 5	**Group 5** Other Scenarios	**17. EE Decrement Method**	Base	Base
		18. Unconstrained Wind and Solar Additions	Base	Base
		19. Reserve Margin Constraint with unconstrained Renewables	Base	Base

5.2.2.1 Group 1 – Optimization Modeling Results Base, High Band, Low Band and No Carbon Commodity Pricing Portfolios

The Group 1 scenarios all assume that Rockport Unit 1 retires at the end of 2028 and Rockport Unit 2 lease expires at the end of 2022. Recall from Section 4.3 that the modeling associated with the Base, High and Low Band commodity price scenarios assumed a CO_2 dispatch burden, or allowance value, equal to $13.61/short ton commencing in 2028 and escalating at 3% per annum thereafter on a nominal dollar basis. The No Carbon commodity pricing condition does not include a CO_2 dispatch burden. The main objective of the Group 1 scenarios analysis is to observe the varying resource selection by type, timing and amount, without limiting the availability of the resources that may be selected, except what was previously described in Section 4 and Section 5.2.1. This provides the Company with resource plans for consideration over differing views of future commodity pricing and customer load conditions. Furthermore, Group 1 results help guide the Company in developing other scenarios, such as the scenarios in Groups 2 & 3. Table 18 shows the capacity additions associated with the Base, High Band, Low Band and No Carbon commodity pricing scenarios. Table 19 shows the associated costs and revenue impacts associated with the different commodity pricing scenarios. Case 1 is used to evaluate other base commodity pricing scenarios as this case minimizes forced constraints and excludes discretionary resource decisions.

Table 18. Cumulative Capacity Additions (MW) for Base, High Band, Low Band & No Carbon Commodity Pricing Scenarios

	Group 1 Scenarios Load Sensitivity																					
	Commodity Pricing	Resource	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Case 1	BASE	New Solar Firm				76	178	254	331	407	483	636	712	788	865	865	865	865	865	865	865	865
		New Solar				*150*	*350*	*500*	*650*	*800*	*950*	*1250*	*1400*	*1550*	*1700*	*1700*	*1700*	*1700*	*1700*	*1700*	*1700*	*1700*
		New Wind Firm				37	55	55	55	55	74	92	111	111	129	148	166	185	203	221	240	258
		New Wind				*300*	*450*	*450*	*450*	*450*	*600*	*750*	*900*	*900*	*1050*	*1200*	*1350*	*1500*	*1650*	*1800*	*1950*	*2100*
		New DG Firm				10	12	15	16	17	17	19	20	22	24	25	28	30	31	33	35	36
		New DSM		19	36	51	63	79	81	90	97	102	101	103	102	102	102	102	105	100	62	88
		New VVO													7	14	20	20	20	20	20	20
		New CC										770	770	770	770	770	770	1540	1540	1540	2695	2695
		New STMP					150	50				100										
		New DR										14	29	43	58	72	86	101	115	129	144	158
Case 2	High Band	New Solar Firm				76	153	229	305	381	458	559	661	737	814	865	865	865	865	865	865	865
		New Solar				*150*	*300*	*450*	*600*	*750*	*900*	*1100*	*1300*	*1450*	*1600*	*1700*	*1700*	*1700*	*1700*	*1700*	*1700*	*1700*
		New Wind Firm				37	74	92	111	129	148	166	185	203	221	240	258	258	258	258	258	258
		New Wind				*300*	*600*	*750*	*900*	*1050*	*1200*	*1350*	*1500*	*1650*	*1800*	*1950*	*2100*	*2100*	*2100*	*2100*	*2100*	*2100*
		New DG Firm				10	12	15	16	17	17	19	20	22	24	25	28	30	31	33	35	36
		New DSM		19	36	51	63	72	82	90	97	104	93	103	101	102	102	100	105	101	65	93
		New VVO													7	14	20	20	20	20	20	20
		New CC										770	770	770	770	770	770	1540	1540	1540	2695	2695
		New STMP					150	50				100										
		New DR										11	22	36	50	65	79	93	108	122	137	151
Case 3	Low Band	New Solar Firm					76	76	153	153	229	305	381	458	534	610	687	763	839	865	865	865
		New Solar					*150*	*150*	*300*	*300*	*450*	*600*	*750*	*900*	*1050*	*1200*	*1350*	*1500*	*1650*	*1700*	*1700*	*1700*
		New Wind Firm				37	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
		New Wind				*300*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*
		New DG Firm				10	12	15	16	17	17	19	20	22	24	25	28	30	31	33	35	36
		New DSM		19	35	48	58	66	76	86	94	96	85	96	96	98	97	94	90	94	59	85
		New VVO																				
		New CC										1155	1155	1155	1155	1155	1155	1925	1925	1925	3080	3080
		New STMP					250	250	150	150	50	100	50									
		New DR																	4	18	32	47
Case 4	No Carbon	New Solar Firm					76	76	153	153	229	305	381	458	534	610	687	763	839	865	865	865
		New Solar					*150*	*150*	*300*	*300*	*450*	*600*	*750*	*900*	*1050*	*1200*	*1350*	*1500*	*1650*	*1700*	*1700*	*1700*
		New Wind Firm				37	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
		New Wind				*300*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*
		New DG Firm				10	12	15	16	17	17	19	20	22	24	25	28	30	31	33	35	36
		New DSM		19	36	49	58	66	76	86	94	96	85	96	96	98	97	95	91	94	59	85
		New VVO																				
		New CC										1155	1155	1155	1155	1155	1155	1925	1925	1925	3080	3080
		New STMP					250	250	150	150	50	100	50									
		New DR																	11	22	36	50

Table 19. Group 1 Cumulative Present Worth Analysis ($000)

	Load Cost	Fuel Costs	Emission Costs	Existing System FOM + OGC	(Incremental) Fixed + Variable + Lease Costs +ST PPA	(Incremental) Capital + Renewable + VVO Program Costs	Contract (Revenue)/Cost	Less: Market Revenue	GRAND TOTAL, Net Utility Costs	(Cost over) Case 1
	Case 1: Base - (RP1 Retires 12/2028; RP2 Lease Expires 12/2022)									
Cumulative Present Worth $000 (2019$)										
Utility CPW 2019-2029	5,517,178	2,289,161	185,485	308,198	1,138,440	836,103	259,958	6,909,927	3,624,597	
Utility CPW 2019-2038	8,924,481	3,155,531	288,588	423,643	1,620,660	2,640,298	225,054	11,251,494	6,026,761	
Utility CPW 2019-2048	11,415,922	3,748,692	391,613	451,629	1,912,267	4,264,759	148,931	13,428,605	8,905,208	
CPW of End Effects beyond 2048									3,052,460	
TOTAL Utility Cost, Net CPW (2019$)									11,957,668	
	Case 2: High Band - (RP1 Retires 12/2028; RP2 Lease Expires 12/2022)									
Cumulative Present Worth $000 (2019$)										
Utility CPW 2019-2029	6,044,177	2,358,732	186,231	308,198	1,134,499	1,112,497	192,181	7,801,130	3,535,383	(89,214)
Utility CPW 2019-2038	9,778,919	3,257,247	280,317	423,643	1,611,329	3,181,124	127,209	12,763,374	5,896,414	(130,346)
Utility CPW 2019-2048	12,522,577	3,855,567	370,358	451,629	1,899,898	4,768,735	41,799	15,040,545	8,870,018	(35,189)
CPW of End Effects beyond 2048									3,170,067	117,607
TOTAL Utility Cost, Net CPW (2019$)									12,040,086	82,418
	Case 3: Low Band - (RP1 Retires 12/2028; RP2 Lease Expires 12/2022)									
Cumulative Present Worth $000 (2019$)										
Utility CPW 2019-2029	4,948,346	2,109,293	172,139	308,198	1,122,222	587,345	331,997	5,918,291	3,661,249	36,652
Utility CPW 2019-2038	7,939,235	3,043,383	307,646	423,643	1,602,517	1,811,574	332,163	9,418,508	6,041,653	14,892
Utility CPW 2019-2048	10,177,062	3,685,908	439,614	451,629	1,895,478	3,009,591	265,455	11,117,887	8,806,851	(98,357)
CPW of End Effects beyond 2048									2,990,915	(61,545)
TOTAL Utility Cost, Net CPW (2019$)									11,797,767	(159,901)
	Case 4: No Carbon - (RP1 Retires 12/2028; RP2 Lease Expires 12/2022)									
Cumulative Present Worth $000 (2019$)										
Utility CPW 2019-2029	5,341,753	2,335,303	131,612	308,198	1,116,109	587,552	271,157	6,524,366	3,567,319	(57,278)
Utility CPW 2019-2038	8,322,667	3,503,036	131,612	423,643	1,604,786	1,812,768	235,376	10,164,028	5,869,861	(156,900)
Utility CPW 2019-2048	10,542,736	4,489,788	131,612	451,629	1,911,051	3,009,589	163,126	12,113,791	8,585,740	(319,468)
CPW of End Effects beyond 2048									2,954,793	(97,668)
TOTAL Utility Cost, Net CPW (2019$)									11,540,533	(417,135)

All four Group 1 scenarios result in similar resource additions, such as:

- Wind resources of 300MW (nameplate) in 2023;
- Solar resources of 150MW (nameplate) beginning as early as 2022 and total solar resource additions of 1,700MW (nameplate) by 2036 depending on the commodity pricing scenario; and
- EE programs beginning in 2020 and DR programs as early as 2028.

This analysis provides I&M information regarding optimum resource selection under various commodity price and load futures. In particular, Group 1 optimizations support adding renewable resources to I&M's fleet.

5.2.2.2 Group 2 - Optimization Modeling Results of Rockport Scenarios

Group 2 scenarios were developed to better understand the dynamic resource selection based on various future conditions related to the Rockport plant. These scenarios were also developed for both Base and No Carbon commodity pricing conditions. The No Carbon cases are identified by the naming convention of adding an "A" to the case name. Furthermore, Group 2 scenarios include the addition of new technologies including the availability of up to 50MW of Battery Storage and 50MW of Mini-Grid resources. Case 5 has the same Rockport assumptions as Case 1, but includes the addition of the Battery Storage and Mini-Grid. Cases 6 and 6A both assume that Rockport Unit 1 has a Flue Gas Desulfurization (FGD) system installed by January 2026 and retires at the end of 2044 and the Rockport Unit 2 lease is not extended. Cases 7 and 7A both assume that Rockport Unit 1 has a FGD system installed by January 2029 and retires at the end of 2044 and the Rockport Unit 2 lease is not extended. Cases 8 and 8A both assume that Rockport Unit 1 retires at the end of 2024, the Rockport Unit 2 lease is extended, and FGD system is installed by January 2029 and retires by the end of 2048.

Table 20 and Table 22 show the cumulative additions by resource type for the Group 2 and 2A scenarios. As expected, the No Carbon scenarios utilized less renewables, particularly wind and relied more on the Combined Cycle resources. Under the base commodity-pricing scenario, Case 5 was identified as the optimum portfolio that balanced renewable resource additions, battery and mini-grid solutions with all other resources while minimizing the Company's generation-related variable and fixed costs as shown in Table 21.

Table 20. Cumulative Capacity Additions (MW) for Base Commodity Pricing Rockport Scenarios

	Group 2 Scenarios Load Sensitivity																					
	Commodity Pricing	Resource	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
		New Solar Firm				76	153	153	229	305	381	458	559	661	737	814	865	865	865	865	865	865
		New Solar				149	299	299	448	597	746	896	1095	1294	1443	1592	1692	1692	1692	1692	1692	1692
		New Wind Firm				37	55	55	55	55	55	74	92	92	111	129	148	166	185	203	221	240
		New Wind				300	450	450	450	450	450	600	750	750	900	1050	1200	1350	1500	1650	1800	1950
		New DG Firm				10	12	15	16	17	17	19	20	22	24	25	28	30	31	33	35	36
		New Microgrid (RICE)				18	18	18	36	36	36	54	54	54	54	54	54	54	54	54	54	54
Case 5	BASE	New DSM		19	36	50	62	71	81	89	97	105	96	102	101	101	101	100	102	97	61	86
		New VVO															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
		New CC										770	770	770	770	770	770	1540	1540	1540	2695	2695
		New STMP				10	10	10	30	30	30	50	50	50	50	50	50	50	50	50	50	50
		New DR															14	29	43	58	72	86
		New Solar Firm					76	76	76	153	229	305	381	534	610	687	763	839	865	865	865	865
		New Solar					149	149	149	299	448	597	746	1045	1194	1344	1493	1642	1692	1692	1692	1692
		New Wind Firm				37	55	55	55	55	74	92	92	92	92	111	129	148	166	185	203	221
		New Wind				300	450	450	450	450	600	750	750	750	750	900	1050	1200	1350	1500	1650	1800
		New DG Firm				10	12	15	16	17	17	19	20	22	24	25	28	30	31	33	35	36
		New Microgrid (RICE)				18	18	18	36	36	36	54	54	54	54	54	54	54	54	54	54	54
Case 6	BASE	New DSM		19	36	51	64	79	83	91	98	101	91	101	100	100	101	104	102	97	61	86
		New VVO																				
		New Battery Storage				10	10	10	30	30	30	50	50	50	50	50	50	50	50	50	50	50
		New CC																385	385	385	1540	1540
		New STMP				10	10	10	30	30	30	50	50	50	50	50	50	50	50	50	50	50
		New DR																14	29	43	58	72
		New Solar Firm					76	76	76	127	203	280	356	509	585	661	737	814	865	865	865	865
		New Solar					149	149	149	249	398	547	697	995	1145	1294	1443	1592	1692	1692	1692	1692
		New Wind Firm				37	55	55	55	55	55	74	92	92	111	129	148	166	185	203	221	240
		New Wind				300	450	450	450	450	450	600	750	750	900	1050	1200	1350	1500	1650	1800	1950
		New DG Firm				10	12	15	16	17	17	19	20	22	24	25	28	30	31	33	35	36
		New Microgrid (RICE)				18	18	18	36	36	36	54	54	54	54	54	54	54	54	54	54	54
Case 7	BASE	New DSM		19	36	51	64	79	83	91	103	102	92	103	102	103	103	111	105	99	62	87
		New VVO																				
		New Battery Storage				10	10	10	30	30	30	50	50	50	50	50	50	50	50	50	50	50
		New CC																385	385	385	1540	1540
		New STMP				10	10	10	30	30	30	50	50	50	50	50	50	50	50	50	50	50
		New DR																14	29	43	58	72
		New Solar Firm							76	76	153	229	305	458	534	610	687	763	839	865	865	865
		New Solar							149	149	299	448	597	896	1045	1194	1344	1493	1642	1692	1692	1692
		New Wind Firm				37	55	55	55	55	55	74	92	92	111	129	148	166	185	203	221	240
		New Wind				300	450	450	450	450	450	600	750	750	900	1050	1200	1350	1500	1650	1800	1950
		New DG Firm				10	12	15	16	17	17	19	20	22	24	25	28	30	31	33	35	36
		New Microgrid (RICE)				18	18	18	36	36	36	54	54	54	54	54	54	54	54	54	54	54
Case 8	BASE	New DSM		19	36	50	59	66	77	86	94	99	89	99	99	100	100	103	102	97	61	86
		New VVO																				
		New Battery Storage				10	10	10	30	30	30	50	50	50	50	50	50	50	50	50	50	50
		New CC																385	385	385	1155	1155
		New STMP				10	10	10	30	30	30	50	50	50	50	50	50	50	50	50	50	50
		New DR																14	29	43	58	72

Table 21. Group 2 Cumulative Present Worth Analysis ($000)

	Load Cost	Fuel Costs	Emission Costs	Existing System FOM + OGC	(Incremental) Fixed + Variable + Lease Costs	(Incremental) Capital + Renewable + VVO Program Costs	Contract (Revenue)/Cost	*Less:* Market Revenue	GRAND TOTAL, Net Utility Costs	(Cost over) Case 5
	Case 5 - Base With Storage and MiniGrid (RP1 Retires 12/2028; RP2 Lease Expires 12/2022)									
Cumulative Present Worth $000 (2019$)										
Utility CPW 2019-2029	5,517,178	2,296,150	185,947	308,198	1,131,086	734,124	259,958	6,803,238	3,629,403	
Utility CPW 2019-2038	8,924,481	3,170,218	290,395	423,643	1,604,070	2,453,821	225,054	11,034,407	6,057,275	
Utility CPW 2019-2048	11,415,922	3,766,943	394,054	451,629	1,888,778	4,083,896	148,931	13,200,185	8,949,968	
CPW of End Effects beyond 2048									3,062,938	
TOTAL Utility Cost, Net CPW (2019$)									12,012,907	
	Case 6 - Base With Storage and MiniGrid (RP1 FGD 1/2026 & Retires 12/2044; RP2 Lease Expires 12/2022)									
Cumulative Present Worth $000 (2019$)										
Utility CPW 2019-2029	5,517,178	2,266,225	286,454	313,982	1,105,056	1,084,294	260,543	6,782,568	4,051,163	421,760
Utility CPW 2019-2038	8,924,481	3,144,866	776,843	497,653	1,527,312	2,922,347	226,003	11,199,975	6,819,529	762,255
Utility CPW 2019-2048	11,415,922	3,752,901	1,092,922	591,035	1,789,008	4,417,866	150,137	13,551,631	9,623,557	673,588
CPW of End Effects beyond 2048									3,225,584	162,645
TOTAL Utility Cost, Net CPW (2019$)									12,849,140	836,234
	Case 7 - Base With Storage and MiniGrid (RP1 FGD 1/2029 & Retires 12/2044; RP2 Lease Expires 12/2022)									
Cumulative Present Worth $000 (2019$)										
Utility CPW 2019-2029	5,517,178	2,233,570	217,154	313,982	1,098,276	662,159	260,542	6,640,230	3,662,631	33,228
Utility CPW 2019-2038	8,924,481	3,114,850	710,474	514,436	1,518,811	2,839,223	226,003	11,136,743	6,711,534	654,260
Utility CPW 2019-2048	11,415,922	3,723,698	1,027,633	643,955	1,780,563	4,346,008	150,137	13,506,077	9,525,670	575,701
CPW of End Effects beyond 2048									3,248,788	185,850
TOTAL Utility Cost, Net CPW (2019$)									12,774,457	761,551
	Case 8 - Base With Storage and MiniGrid (RP1 Retires 1/2025; RP2 Lease Extended, FGD 1/2029, & Retires 12/2048)									
Cumulative Present Worth $000 (2019$)										
Utility CPW 2019-2029	5,517,178	2,565,591	227,761	365,162	1,698,751	617,284	260,542	7,010,558	4,241,711	612,308
Utility CPW 2019-2038	8,924,481	3,333,047	625,055	578,357	2,556,961	2,748,067	226,002	11,250,773	7,741,197	1,683,923
Utility CPW 2019-2048	11,415,922	3,919,598	990,883	714,779	2,802,532	4,156,311	150,136	13,635,473	10,458,519	1,508,551
CPW of End Effects beyond 2048									2,915,269	(147,669)
TOTAL Utility Cost, Net CPW (2019$)									13,373,788	1,360,881

Table 22. Group 2A Cumulative Capacity Additions (MW) for Rockport Scenarios

	Group 2A Scenarios Load Sensitivity																					
	Commodity Pricing	Resource	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Case 5A	BASE	New Solar Firm					76	76	153	229	305	381	458	534	610	687	763	839	865	865	865	865
		New Solar					*150*	*150*	*300*	*450*	*600*	*750*	*900*	*1050*	*1200*	*1350*	*1500*	*1650*	*1700*	*1700*	*1700*	*1700*
		New Wind Firm				37	55	55	55	55	55	55	55	55	55	55	55	55	55	55	74	92
		New Wind				*300*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*600*	*750*
		New DG Firm				10	12	15	16	17	17	19	20	22	24	25	28	30	31	33	35	36
		New Microgrid (RICE)				*18*	*18*	*18*	*36*	*36*	*36*	*54*	*54*	*54*	*54*	*54*	*54*	*54*	*54*	*54*	*54*	*54*
		New DSM		15	30	42	57	61	68	82	78	79	70	77	77	78	78	76	73	78	48	71
		New VVO																				
		New Battery Storage				10	10	10	30	30	30	50	50	50	50	50	50	50	50	50	50	50
		New CC										*1155*	*1155*	*1155*	*1155*	*1155*	*1155*	*1925*	*1925*	*1925*	*3080*	*3080*
		New STMP				10	10	10	30	30	30	50	50	50	50	50	50	50	50	50	50	50
		New DR																14	29	43	58	72
Case 6A	BASE	New Solar Firm					76	76	76	153	229	305	381	483	559	636	712	788	865	865	865	865
		New Solar					*150*	*150*	*150*	*300*	*450*	*600*	*750*	*950*	*1100*	*1250*	*1400*	*1550*	*1700*	*1700*	*1700*	*1700*
		New Wind Firm				37	55	55	55	55	55	55	55	55	55	55	55	55	74	92	111	129
		New Wind				*300*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*600*	*750*	*900*	*1050*
		New DG Firm				10	12	15	16	17	17	19	20	22	24	25	28	30	31	33	35	36
		New Microgrid (RICE)				*18*	*18*	*18*	*36*	*36*	*36*	*54*	*54*	*54*	*54*	*54*	*54*	*54*	*54*	*54*	*54*	*54*
		New DSM		19	36	51	72	72	82	90	104	100	88	98	98	99	100	103	106	102	63	89
		New VVO															*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
		New CC																*385*	*385*	*385*	*1540*	*1540*
		New STMP				10	10	10	30	30	30	50	50	50	50	50	50	50	50	50	50	50
		New DR					7	7	7	7	7	7	7	7	7	22	36	50	65	79	93	101
Case 7A	BASE	New Solar Firm					76	76	76	127	203	280	356	483	559	636	712	788	865	865	865	865
		New Solar					*150*	*150*	*150*	*250*	*400*	*550*	*700*	*950*	*1100*	*1250*	*1400*	*1550*	*1700*	*1700*	*1700*	*1700*
		New Wind Firm				37	55	55	55	55	55	55	55	55	55	55	55	55	74	92	111	129
		New Wind				*300*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*600*	*750*	*900*	*1050*
		New DG Firm				10	12	15	16	17	17	19	20	22	24	25	28	30	31	33	35	36
		New Microgrid (RICE)				*18*	*18*	*18*	*36*	*36*	*36*	*54*	*54*	*54*	*54*	*54*	*54*	*54*	*54*	*54*	*54*	*54*
		New DSM		19	36	51	72	72	81	89	96	99	88	98	98	99	99	103	106	102	63	89
		New VVO															*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
		New CC																*385*	*385*	*385*	*1540*	*1540*
		New STMP				10	10	10	30	30	30	50	50	50	50	50	50	50	50	50	50	50
		New DR					7	7	7	7	7	7	7	7	7	22	36	50	65	79	93	101
Case 8A	BASE	New Solar Firm							25	76	153	229	305	407	483	559	636	712	788	865	865	865
		New Solar							*50*	*150*	*300*	*450*	*600*	*800*	*950*	*1100*	*1250*	*1400*	*1550*	*1700*	*1700*	*1700*
		New Wind Firm				37	55	55	55	55	55	55	55	55	55	55	55	74	92	111	129	148
		New Wind				*300*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*600*	*750*	*900*	*1050*	*1200*
		New DG Firm				10	12	15	16	17	17	19	20	22	24	25	28	30	31	33	35	36
		New Microgrid (RICE)				*18*	*18*	*18*	*36*	*36*	*36*	*54*	*54*	*54*	*54*	*54*	*54*	*54*	*54*	*54*	*54*	*54*
		New DSM		19	36	50	59	66	77	86	94	96	86	96	96	98	97	96	99	95	60	86
		New VVO																				
		New Battery Storage				10	10	10	30	30	30	50	50	50	50	50	50	50	50	50	50	50
		New CC																*385*	*385*	*385*	*1540*	*1540*
		New STMP				10	10	10	30	30	30	50	50	50	50	50	50	50	50	50	50	50
		New DR																14	29	43	58	72

Table 23. Group 2A Cumulative Present Worth Analysis ($000)

	Load Cost	Fuel Costs	Emission Costs	Existing System FOM + OGC	(Incremental) Fixed + Variable + Lease Costs	(Incremental) Capital + Renewable + VVO Program Costs	Contract (Revenue)/Cost	*Less:* Market Revenue	GRAND TOTAL, Net Utility Costs	(Cost over) Case 5A
Case 5A - No Carbon With Storage and MiniGrid (RP1 Retires 12/2028; RP2 Lease Expires 12/2022)										
Cumulative Present Worth $000 (2019$)										
Utility CPW 2019-2029	5,341,753	2,287,440	131,612	308,198	1,126,866	711,919	208,518	6,552,669	3,563,637	
Utility CPW 2019-2038	8,322,667	3,269,467	131,612	423,643	1,611,460	2,071,594	161,189	10,115,367	5,876,265	
Utility CPW 2019-2048	10,542,736	4,137,700	131,612	451,629	1,912,776	3,628,934	88,938	12,290,390	8,603,935	
CPW of End Effects beyond 2048									2,905,196	
TOTAL Utility Cost, Net CPW (2019$)									11,509,130	
Case 6A - No Carbon With Storage and MiniGrid (RP1 FGD 1/2026 & Retires 12/2044; RP2 Lease Expires 12/2022)										
Cumulative Present Worth $000 (2019$)										
Utility CPW 2019-2029	5,341,753	2,288,023	196,429	313,982	1,095,911	1,032,498	209,084	6,459,467	4,018,213	454,576
Utility CPW 2019-2038	8,322,667	3,344,781	329,013	497,653	1,517,889	2,540,361	162,074	10,010,028	6,704,410	828,145
Utility CPW 2019-2048	10,542,736	4,215,353	388,257	591,035	1,789,649	3,941,644	90,052	12,155,476	9,368,647	764,712
CPW of End Effects beyond 2048									3,070,255	165,059
TOTAL Utility Cost, Net CPW (2019$)									12,438,902	929,771
Case 7A- No Carbon With Storage and MiniGrid (RP1 FGD 1/2029 & Retires 12/2044; RP2 Lease Expires 12/2022)										
Cumulative Present Worth $000 (2019$)										
Utility CPW 2019-2029	5,341,753	2,307,992	163,352	313,982	1,094,442	621,345	188,811	6,651,647	3,380,029	(183,608)
Utility CPW 2019-2038	8,322,667	3,674,341	370,381	514,436	1,529,691	2,389,903	102,921	10,965,763	5,938,577	62,312
Utility CPW 2019-2048	10,542,736	4,690,444	463,701	643,955	1,807,507	3,791,529	20,128	13,337,555	8,566,277	(37,658)
CPW of End Effects beyond 2048									3,097,301	192,105
TOTAL Utility Cost, Net CPW (2019$)									11,663,577	154,447
Case 8A - No Carbon With Storage and MiniGrid (RP1 Retires 1/2025; RP2 Lease Extended, FGD 1/2029, & Retires 12/2048)										
Cumulative Present Worth $000 (2019$)										
Utility CPW 2019-2029	5,341,753	2,669,943	188,192	365,162	1,699,601	568,704	188,811	7,065,824	3,956,341	392,705
Utility CPW 2019-2038	8,322,667	3,959,839	376,930	578,357	2,569,905	2,337,005	102,921	11,257,596	6,990,028	1,113,763
Utility CPW 2019-2048	10,542,736	5,026,032	507,724	714,779	2,833,543	3,646,740	20,128	13,716,153	9,519,362	915,427
CPW of End Effects beyond 2048									2,719,576	(185,619)
TOTAL Utility Cost, Net CPW (2019$)									12,238,938	729,807

5.2.2.3 Group 3 - Optimization Modeling Results of IRP Scenarios

Group 3 scenarios were developed to better understand specific resource constraints and their impact on resource selection. The Group 3 scenarios all assume that Rockport Unit 1 retires at the end of 2028 and Rockport Unit 2 lease expires at the end of 2022. Like Group 2, Group 3 scenarios also include the addition of 50MW of Battery Storage and 50MW of Mini-Grid resources. The Case 9 (Transitional case) results ended up being the same as the Group 2's Case 5 results. In the initial Case 9 model run, a constraint was added to prevent assigning the NGCC resource until 2028; however, the final optimizations did not require this forced constraint. Cases 10 & 11 both constrained the model to delay the potential addition of a NGCC for various different time periods. Case 10 delays the potential NGCC build to 2034 and Case 11 delays the potential NGCC build to 2037. By developing both Case 10 and 11, these cases allow the Company to analyze the resource selection when the model is not allowed to build a NGCC during these periods. Cases 12 and 12A, described as "High Renewables", are two cases developed at the request of the various stakeholders. "High Renewables" has been defined as 2 times the levels of renewables that are included all other cases both on a cumulative and annual basis. I&M considers the High Renewables plan as an aggressive build-out of renewable resources which may not be practical, however as the Company solicits the market for renewable opportunities it will consider reasonable economic resource additions above quantities identified in the final Preferred Plan.

The various resource selections for Group 3 cases are shown in Table 24 and the associated costs and revenues over the planning period in Table 25. Case 9 was identified to be the optimum plan in this group, providing a good blend of resources that permit flexibility in how the Company will meet its PJM reserve requirements while minimizing the costs over the 20 year IRP planning period.

Table 24. Group 3 Cumulative Capacity Additions (MW) for Base Commodity Pricing IRP Scenarios

	Group 3 Scenarios Load Sensitivity																					
	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*
		New Wind Firm				37	55	55	55	55	55	74	92	92	111	129	148	166	185	203	221	240
		New Wind				*300*	*450*	*450*	*450*	*450*	*450*	*600*	*750*	*750*	*900*	*1050*	*1200*	*1350*	*1500*	*1650*	*1800*	*1950*
		New DG Firm				10	12	15	16	17	17	19	20	22	24	25	28	30	31	33	35	36
		New Microgrid (RICE)				18	18	18	36	36	36	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*
		New VVO															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
		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
Case 10	BASE	New Solar Firm				76	153	178	254	331	407	559	712	814	865	865	865	865	865	865	865	865
		New Solar				*150*	*300*	*350*	*500*	*650*	*800*	*1100*	*1400*	*1600*	*1700*	*1700*	*1700*	*1700*	*1700*	*1700*	*1700*	*1700*
		New Wind Firm				37	74	74	92	111	129	148	166	185	203	221	240	240	258	258	258	258
		New Wind				*300*	*600*	*600*	*750*	*900*	*1050*	*1200*	*1350*	*1500*	*1650*	*1800*	*1950*	*1950*	*2100*	*2100*	*2100*	*2100*
		New DG Firm				10	12	15	16	17	17	19	20	22	24	25	28	30	31	33	35	36
		New Microgrid (RICE)				18	18	18	36	36	36	54	54	54	54	54	54	54	54	54	54	54
		New CT										248	248	248	248	248	248	248	248	248	248	248
		New DSM		*19*	*36*	*51*	*69*	*78*	*83*	*92*	*99*	*113*	*96*	*112*	*107*	*115*	*106*	*103*	*107*	*103*	*65*	*94*
		New VVO					9	9	9	9	9	9	9	9	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
		New CC																1155	1155	1155	2310	2310
		New STMP					50					400	250	100	50	50	50					
		New DR		14	29	43	58	72	86	101	115	129	144	158	158	162	162	162	147	137	122	111
Case 11	BASE	New Solar Firm				76	153	178	254	331	407	559	687	788	865	865	865	865	865	865	865	865
		New Solar				*150*	*300*	*350*	*500*	*650*	*800*	*1100*	*1350*	*1550*	*1700*	*1700*	*1700*	*1700*	*1700*	*1700*	*1700*	*1700*
		New Wind Firm				37	74	74	92	111	129	148	166	185	203	221	240	258	258	258	258	258
		New Wind				*300*	*600*	*600*	*750*	*900*	*1050*	*1200*	*1350*	*1500*	*1650*	*1800*	*1950*	*2100*	*2100*	*2100*	*2100*	*2100*
		New DG Firm				10	12	15	16	17	17	19	20	22	24	25	28	30	31	33	35	36
		New Microgrid (RICE)				18	18	18	36	36	36	54	54	54	54	54	54	54	54	54	54	54
		New CT										248	248	248	248	248	248	1240	1240	1240	1240	1240
		New DSM		*19*	*37*	*55*	*77*	*87*	*88*	*95*	*101*	*106*	*101*	*117*	*118*	*120*	*110*	*108*	*112*	*106*	*66*	*93*
		New VVO									9	16	23	29	29	29	29	29	29	29	29	29
		New Battery Storage				10	10	10	30	30	30	50	50	50	50	50	50	50	50	50	50	50
		New CC																			1155	1155
		New STMP					50					400	250	100						50	50	50
		New DR		14	29	43	58	72	86	101	115	129	144	158	173	187	201	216	216	216	216	216
Case 12	BASE	New Solar Firm				51	203	203	356	509	661	941	1093	1246	1399	1551	1704	1729	1729	1729	1729	1729
		New Solar				*100*	*400*	*400*	*700*	*1000*	*1300*	*1850*	*2150*	*2450*	*2750*	*3050*	*3350*	*3400*	*3400*	*3400*	*3400*	*3400*
		New Wind Firm				74	111	111	111	111	148	185	221	240	277	314	351	387	424	461	498	517
		New Wind				*600*	*900*	*900*	*900*	*900*	*1200*	*1500*	*1800*	*1950*	*2250*	*2550*	*2850*	*3150*	*3450*	*3750*	*4050*	*4200*
		New DG Firm				26	36	41	42	44	45	47	50	52	55	60	63	59	59	59	59	59
		New Microgrid (RICE)				18	18	18	36	36	36	54	54	54	54	54	54	54	54	54	54	54
		New CT																248	248	248	1240	1240
		New DSM		*19*	*36*	*51*	*70*	*71*	*80*	*89*	*96*	*100*	*98*	*101*	*101*	*102*	*102*	*102*	*107*	*103*	*65*	*94*
		New VVO															6	15	22	22	28	35
		New Battery Storage				10	10	10	30	30	30	50	50	50	50	50	50	50	50	50	50	50
		New CC																				
		New STMP										300	100					50			100	50
		New DR					4	4	18	32	47	61	76	90	104	119	133	147	162	176	191	201
Case 12A	BASE	New Solar Firm				51	203	203	331	483	636	788	966	1246	1399	1551	1704	1729	1729	1729	1729	1729
		New Solar				*100*	*400*	*400*	*650*	*950*	*1250*	*1550*	*1900*	*2450*	*2750*	*3050*	*3350*	*3400*	*3400*	*3400*	*3400*	*3400*
		New Wind Firm				74	111	111	111	111	148	185	221	221	258	295	332	369	406	443	480	517
		New Wind				*600*	*900*	*900*	*900*	*900*	*1200*	*1500*	*1800*	*1800*	*2100*	*2400*	*2700*	*3000*	*3300*	*3600*	*3900*	*4200*
		New DG Firm				26	36	41	42	44	45	47	50	52	55	60	63	59	59	59	59	59
		New Microgrid (RICE)				18	18	18	36	36	36	54	54	54	54	54	54	54	54	54	54	54
		New CT																				
		New DSM		*19*	*37*	*53*	*74*	*73*	*82*	*90*	*97*	*102*	*92*	*102*	*101*	*102*	*101*	*100*	*105*	*101*	*64*	*91*
		New VVO														9	16	16	16	16	16	16
		New Battery Storage				10	10	10	30	30	30	50	50	50	50	50	50	50	50	50	50	50
		New CC																385	385	385	1540	1540
		New STMP										500	300									
		New DR										4	11	25	36	50	65	79	93	108	122	137

Table 25. Group 3 Cumulative Present Worth Analysis ($000)

	Load Cost	Fuel Costs	Emission Costs	Existing System FOM + OGC	(Incremental) Fixed + Variable + Lease Costs	(Incremental) Capital + Renewable + VVO Program Costs	Contract (Revenue)/Cost	*Less:* Market Revenue	GRAND TOTAL, Net Utility Costs	(Cost over) Case 9
Case 9 - Preferred, Storage and MiniGrid (RP1 Retires 12/2028; RP2 Lease Expires 12/2022)										
Cumulative Present Worth $000 (2019$)										
Utility CPW 2019-2029	5,517,178	2,296,150	185,947	308,198	1,131,086	748,301	259,958	6,817,693	3,629,125	
Utility CPW 2019-2038	8,924,481	3,170,218	290,395	423,643	1,604,070	2,475,507	225,054	11,063,729	6,049,639	
Utility CPW 2019-2048	11,415,922	3,766,943	394,054	451,629	1,888,778	4,112,069	148,931	13,239,036	8,939,290	
CPW of End Effects beyond 2048									3,052,665	
TOTAL Utility Cost, Net CPW (2019$)									11,991,955	
Case 10: 12 - Year Peaking (RP1 Retires 12/2028; RP2 Lease Expires 12/2022)										
Cumulative Present Worth $000 (2019$)										
Utility CPW 2019-2029	5,517,178	2,180,104	166,450	308,198	1,141,619	1,059,979	259,958	6,882,280	3,751,205	122,080
Utility CPW 2019-2038	8,924,481	2,797,886	227,027	423,643	1,619,828	3,024,383	225,054	11,071,060	6,171,241	121,602
Utility CPW 2019-2048	11,415,922	3,384,243	328,895	451,629	1,907,955	4,662,687	148,931	13,210,155	9,090,108	150,818
CPW of End Effects beyond 2048									3,110,874	58,209
TOTAL Utility Cost, Net CPW (2019$)									12,200,982	209,027
Case 11: 15 - Year Peaking (RP1 Retires 12/2028; RP2 Lease Expires 12/2022)										
Cumulative Present Worth $000 (2019$)										
Utility CPW 2019-2029	5,517,178	2,180,104	166,450	308,198	1,140,816	1,061,540	259,958	6,881,629	3,752,614	123,489
Utility CPW 2019-2038	8,924,481	2,571,292	187,865	423,643	1,642,656	3,055,392	225,054	10,747,038	6,283,345	233,706
Utility CPW 2019-2048	11,415,922	2,916,160	247,889	451,629	1,967,202	4,686,895	148,931	12,538,877	9,295,751	356,461
CPW of End Effects beyond 2048									3,177,138	124,473
TOTAL Utility Cost, Net CPW (2019$)									12,472,888	480,933
Case 12: High Renewables - Peaking (RP1 Retires 12/2028; RP2 Lease Expires 12/2022)										
Cumulative Present Worth $000 (2019$)										
Utility CPW 2019-2029	5,517,178	2,178,193	166,113	308,198	1,218,693	1,264,394	259,958	7,158,580	3,754,147	125,022
Utility CPW 2019-2038	8,924,481	2,466,042	169,467	423,643	1,807,263	4,040,215	225,054	11,964,993	6,091,171	41,532
Utility CPW 2019-2048	11,415,922	2,487,887	173,419	451,629	2,186,732	6,425,844	148,931	14,491,072	8,799,293	(139,997)
CPW of End Effects beyond 2048									2,685,436	(367,229)
TOTAL Utility Cost, Net CPW (2019$)									11,484,729	(507,226)
Case 12A: High Renewables - Peaking and CC										
Cumulative Present Worth $000 (2019$)										
Utility CPW 2019-2029	5,517,178	2,178,193	166,113	308,198	1,213,383	1,185,505	259,958	7,123,077	3,705,451	76,326
Utility CPW 2019-2038	8,924,481	2,623,889	196,819	423,643	1,786,813	3,880,173	225,054	12,095,261	5,965,610	(84,029)
Utility CPW 2019-2048	11,415,922	2,966,402	256,325	451,629	2,114,797	6,246,919	148,931	15,087,447	8,513,478	(425,812)
CPW of End Effects beyond 2048									2,544,620	(508,045)
TOTAL Utility Cost, Net CPW (2019$)									11,058,098	(933,857)

5.2.2.4 Group 4 – Optimization Modeling Results of Load & Commodity Sensitivity Scenarios

Group 4 scenarios considers resource selection based on various load and commodity price combinations. Group 4 scenarios also assume that Rockport Unit 1 retires at the end of 2028 and Rockport Unit 2 lease expires at the end of 2022. Table 26 describes the various scenarios considered for the Group 4 scenarios and shows the capacity additions associated with the Low Load, High Load, Low Load with Low Band pricing and High Load with High Band pricing sensitivity scenarios. Both the Low Load with Low Band pricing and the High Load with High Band pricing were developed and modeled as requested by the Michigan Public Service Commission staff.

Table 26. Group 4 - Cumulative Capacity Additions (MW) for Load & Commodity Sensitivity Scenarios

	Group 4 Scenarios Load Sensitivity																					
	Commodity Pricing	Resource	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Case 13	BASE	New Solar Firm					76	76	153	229	305	381	534	687	763	839	865	865	865	865	865	865
		New Solar					*150*	*150*	*300*	*450*	*600*	*750*	*1050*	*1350*	*1500*	*1650*	*1700*	*1700*	*1700*	*1700*	*1700*	*1700*
		New Wind Firm				37	55	55	55	55	74	92	111	129	148	166	185	203	221	240	258	258
		New Wind				*300*	*450*	*450*	*450*	*450*	*600*	*750*	*900*	*1050*	*1200*	*1350*	*1500*	*1650*	*1800*	*1950*	*2100*	*2100*
		New DG Firm				10	12	15	16	17	17	19	20	22	24	25	28	30	31	33	35	36
		New DSM		19	36	50	62	71	82	90	98	107	102	105	103	103	102	107	105	99	62	88
		New VVO											9	9	9	9	9	9	9	9	9	9
		New CC										385	385	385	385	385	385	1155	1155	1155	2310	2310
		New STMP					100	50				450	250	50								
		New DR										14	29	40	40	40	54	54	54	54	54	54
Case 14	BASE	New Solar Firm					51	51	51	127	203	280	407	559	636	712	788	865	865	865	865	865
		New Solar					*100*	*100*	*100*	*250*	*400*	*550*	*800*	*1100*	*1250*	*1400*	*1550*	*1700*	*1700*	*1700*	*1700*	*1700*
		New Wind Firm				37	55	55	55	55	55	74	92	111	129	148	166	185	203	221	240	258
		New Wind				*300*	*450*	*450*	*450*	*450*	*450*	*600*	*750*	*900*	*1050*	*1200*	*1350*	*1500*	*1650*	*1800*	*1950*	*2100*
		New DG Firm				10	12	15	16	17	17	19	20	22	24	25	28	30	31	33	35	36
		New DSM		19	36	50	61	69	79	88	96	101	99	102	101	101	101	103	105	103	66	94
		New VVO											9	9	9	9	9	9	9	9	9	9
		New CC					385	385	385	385	385	1155	1155	1155	1155	1155	1155	1925	1925	1925	3080	3080
		New STMP										300	150						50	50	50	50
		New DR										7	22	29	29	32	47	61	76	90	104	119
Case 15	Low Band	New Solar Firm					76	76	76	127	203	280	356	483	559	636	712	788	865	865	865	865
		New Solar					*150*	*150*	*150*	*250*	*400*	*550*	*700*	*950*	*1100*	*1250*	*1400*	*1550*	*1700*	*1700*	*1700*	*1700*
		New Wind Firm				37	55	55	55	55	55	55	55	55	55	55	55	74	74	74	74	74
		New Wind				*300*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*600*	*600*	*600*	*600*	*600*
		New DG Firm				10	12	15	16	17	17	19	20	22	24	25	28	30	31	33	35	36
		New DSM		19	35	49	60	68	79	88	95	100	98	100	100	101	101	108	100	102	65	91
		New VVO															9	9	9	9	9	9
		New CC										770	770	770	770	770	770	1155	1155	1155	2310	2310
		New STMP					100	50				200	100					150	50	50		
		New DR									11	25	40	50	65	79	93	108	122	137	151	151
Case 16	High Band	New Solar Firm				76	153	229	305	381	458	610	712	814	865	865	865	865	865	865	865	865
		New Solar				*150*	*300*	*450*	*600*	*750*	*900*	*1200*	*1400*	*1600*	*1700*	*1700*	*1700*	*1700*	*1700*	*1700*	*1700*	*1700*
		New Wind Firm				37	74	92	111	129	148	166	185	203	221	240	258	258	258	258	258	258
		New Wind				*300*	*600*	*750*	*900*	*1050*	*1200*	*1350*	*1500*	*1650*	*1800*	*1950*	*2100*	*2100*	*2100*	*2100*	*2100*	*2100*
		New DG Firm				10	12	15	16	17	17	19	20	22	24	25	28	30	31	33	35	36
		New DSM		19	36	51	64	75	84	92	99	109	101	103	102	103	102	102	106	102	65	91
		New VVO										9	9	9	9	9	9	9	9	9	9	9
		New CC										770	770	770	770	770	770	1925	1925	1925	3080	3080
		New STMP					250	150	50			200	100									50
		New DR					11	14	14	14	29	43	58	65	65	65	79	93	108	122	137	137

As expected, the overall capacity additions in the High Load scenario are naturally greater than those in the Low Load scenario, due to the higher load requirement. The High Load scenario calls for solar resources sooner and in greater amounts.

5.2.2.5 Group 5 - Optimization Modeling Results Other Scenarios

Group 5 consists of additional stakeholder requested options. Case 17 is the "EE Decrement" case. This case looked at quantifying the value of forcing in levels of "energy saving" related to undefined energy efficiency programs with no implementation cost. Case 17 results were presented at Stakeholder Meeting #3 and show that if load can be reduced it does reduce the cost of the plan; however, it is important to note that this case included only a hypothetical condition where no costs were assigned to achieve the modeled load reductions. Case 18 is referred to as "Unconstrained Wind and Solar Additions". In this case new wind and solar additions were constrained to 10,000 blocks per tier or tranche of wind or solar, which the Company considers not realistic or practical. Case 19 was similar to Case 18, except for the total PJM Forecasted Pool Requirement limit was set at 20%, or approximately 10% higher than the required level. This case allows the model to select unconstrained renewable resources as well as other resources in the model up to the Reserve Margin limit. The results of Case 18 and Case 19 was presented at Stakeholder Meeting #4 and show that reasonable resource constraints are required to have reasonable modeling results.

5.3 Preferred Plan

Each of the scenarios provides insight into a potential alternative mix of resources for the future. I&M is proposing "Case 9 – Transitional" as its Preferred Plan.

I&M selected this plan based on the following considerations:

- Minimizing revenue requirements (i.e. cost to customers) over the planning period, while meeting capacity obligations.
- Addressing near term capacity needs with Energy Efficiency, Demand Response, Wind, Solar and Short-Term Capacity purchases.
- Including Battery Storage and Mini-Grid resources to ensure the Company gains a better understanding of how these resources may benefit the customers.

- Addressing longer-term capacity needs with the inclusion of highly efficient Natural Gas Combined Cycle resources in later years of the planning period.

The cumulative capacity additions associated with the Preferred Plan are shown below in Table 27.

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*
		New Wind Firm				37	55	55	55	55	55	74	92	92	111	129	148	166	185	203	221	240
		New Wind				*300*	*450*	*450*	*450*	*450*	*450*	*600*	*750*	*750*	*900*	*1050*	*1200*	*1350*	*1500*	*1650*	*1800*	*1950*
		New DG Firm				10	12	15	16	17	17	19	20	22	24	25	28	30	31	33	35	36
		New Microgrid (RICE)				18	18	18	36	36	36	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*
		New VVO															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
		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

In conjunction with the Company's short-term action plan, the Preferred Plan offers I&M significant flexibility should future conditions differ considerably from the assumptions underpinning the Preferred Plan. For example, as EE programs are implemented, I&M will gain insight into customer acceptance and develop additional hard data as to the impact these programs have on load growth. This will assist I&M in determining whether to expand program offerings, change incentive levels for programs, or target specific customer classes for the best results. If current long-term renewable cost assumptions change, I&M could either accelerate or delay the installation of renewable generation facilities. 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.

5.3.1 Demand-Side Resources

In the Preferred Plan, incremental DSM and EE resources were selected beginning in 2020 and throughout the remainder of the planning period. Economic savings are attributable to both Commercial/Industrial and Residential selected bundles, with the majority coming from Commercial bundles especially in the 2020 through 2029 timeframe. In 2029, the EE resources included in the Preferred Plan are expected to reduce energy usage by approximately 745GWhs. Figure 29 shows the cumulative impact on Energy savings of incremental Company sponsored

EE resources included in the Preferred Plan on a percentage basis. Table 27 shows the capacity impact of EE resources for the Preferred Plan.

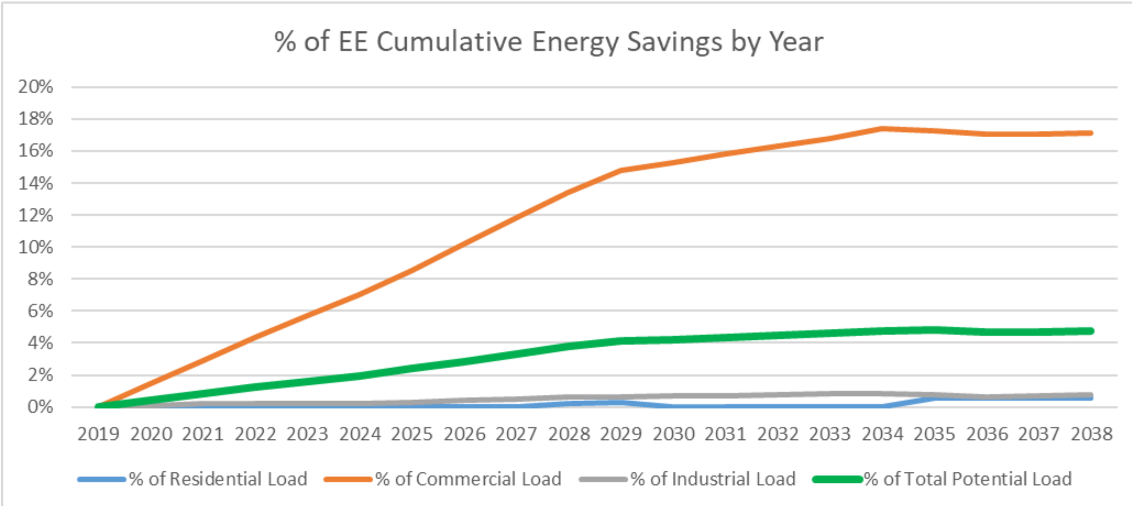

Figure 29. Preferred Plan Cumulative Energy Efficiency Energy Savings (%)

As part of the Preferred Plan, one of the fifteen available EECO tranches is proposed. The selection of this resource is delayed until 2033 and results in a cumulative capacity reduction of 9MW. The EECO estimates are subject to future revision as more operational information regarding the performance of this technology is gained.

DG (i.e. rooftop solar) resources were not modeled during the planning period. DG resources were added incrementally at a CAGR of 10.3% (based on nameplate capacity), resulting in a total of 36MW of PJM capacity credit (88MW nameplate) by 2038.

5.3.2 Preferred Portfolio Cost

Another method of evaluating whether a proposed plan is reasonable is to compare the cost of the proposed plan to other portfolios under consideration. Table 28 shows the comparative cumulative present worth (CPW) and the associated Levelized Annual Bill Impact[19] of the

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[19] The Levelized Annual Bill Impact is an indicative estimate of the incremental cost compared to Case 1 – Base Optimization. This indicative estimate is only capturing the costs and benefits related to the proposed resource additions included in this IRP. The estimate assumes the impact to an "Average Customer" that uses 12,000 kWh per year.

different optimized portfolios from the different groups. Table 29 shows the associated component costs and revenues for each optimized portfolio. The CPW between the optimum portfolios over time are illustrated in Figure 30.

	Cummulative Present Worth Cost over Case 1		Levelized Annual Bill Impact over Case 1 ($)	
	thru 2029	thru 2038	thru 2029	thru 2038
Case 1 - Base Optimization	-	-	-	-
Case 9 - Preferred Plan	$ 4,528	$ 22,878	$ 0.33	$ 1.16
Case 12 - High Renewables	$ 129,550	$ 64,410	$ 9.38	$ 3.38
Case 7 - Rockport U1 FGD 1/2029	$ 38,034	$ 684,774	$ 2.73	$ 34.82

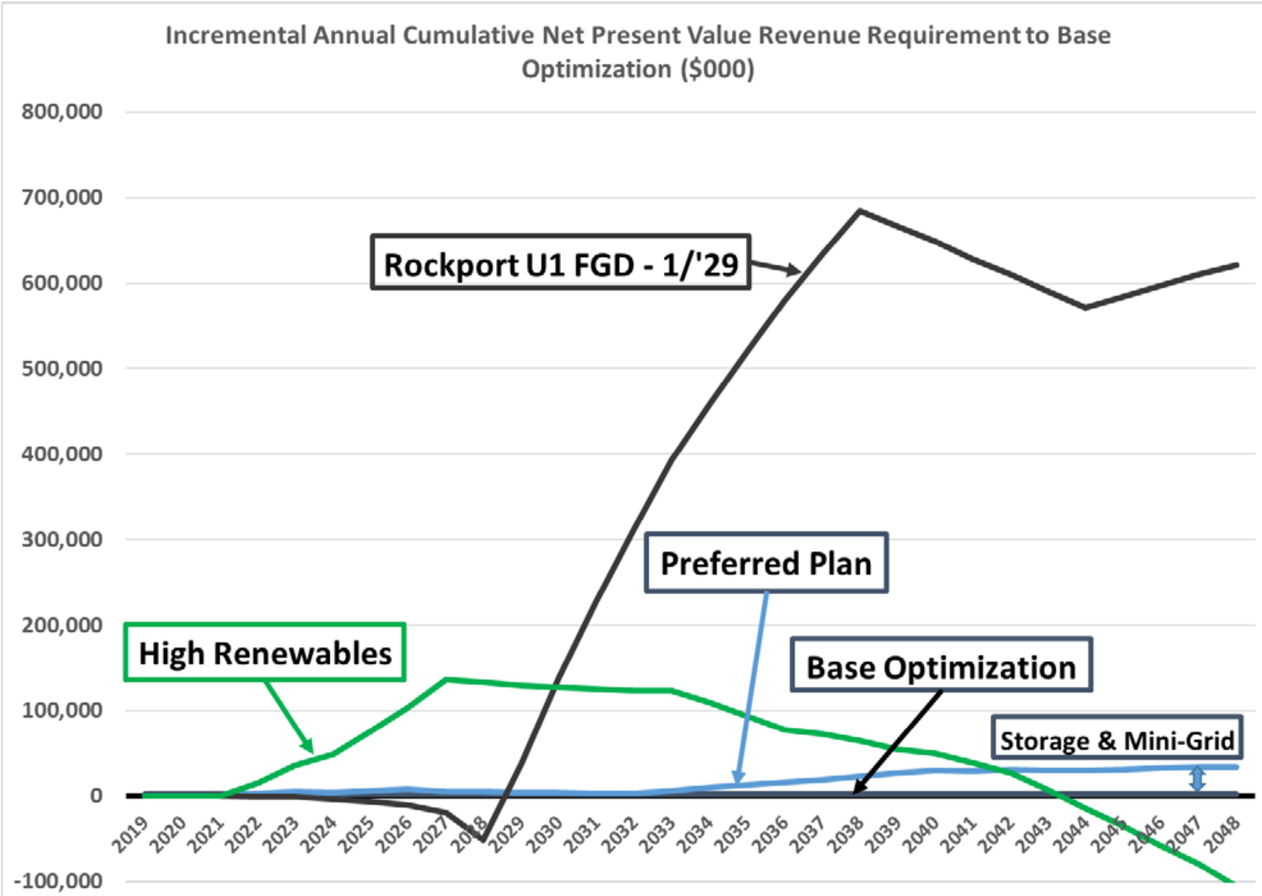
Table 28. Preferred Plan cost comparison to optimum portfolios

While the Preferred Plan results in slightly higher costs over the Case 1 plan due to the addition of storage and mini-grid resources, the costs are closely aligned and allows the Company flexibility in the future to adjust to any conditions that differ from assumptions made for this IRP and to begin to integrate new technologies to benefit customers. While the High Renewable plan begins to show a favorable cost position after 2040, it is more costly to I&M customers over the 20 year IRP planning period and is based on assumptions that the Company considers to be impractical at this time.

Table 29. Preferred Plan vs. Optimized Plans based on Cumulative Present Worth ($000) Analysis

	Load Cost	Fuel Costs	Emission Costs	Existing System FOM + OGC	(Incremental) Fixed + Variable + Lease Costs	(Incremental) Capital + Renewable + VVO Program Costs	Contract (Revenue)/Cost	*Less:* Market Revenue	GRAND TOTAL, Net Utility Costs	(Cost over) Case 1
	Case 1: Base - (RP1 Retires 12/2028; RP2 Lease Expires 12/2022)									
Cumulative Present Worth $000 (2019$)										
Utility CPW 2019-2029	5,517,178	2,289,161	185,485	308,198	1,138,440	836,103	259,958	6,909,927	3,624,597	
Utility CPW 2019-2038	8,924,481	3,155,531	288,588	423,643	1,620,660	2,640,298	225,054	11,251,494	6,026,761	
Utility CPW 2019-2048	11,415,922	3,748,692	391,613	451,629	1,912,267	4,264,759	148,931	13,428,605	8,905,208	
CPW of End Effects beyond 2048									3,052,460	
TOTAL Utility Cost, Net CPW (2019$)									11,957,668	
	Case 7 - Base With Storage and MiniGrid (RP1 FGD 1/2029 & Retires 12/2044; RP2 Lease Expires 12/2022)									
Cumulative Present Worth $000 (2019$)										
Utility CPW 2019-2029	5,517,178	2,233,570	217,154	313,982	1,098,276	662,159	260,542	6,640,230	3,662,631	38,034
Utility CPW 2019-2038	8,924,481	3,114,850	710,474	514,436	1,518,811	2,839,223	226,003	11,136,743	6,711,534	684,774
Utility CPW 2019-2048	11,415,922	3,723,698	1,027,633	643,955	1,780,563	4,346,008	150,137	13,506,077	9,525,670	620,462
CPW of End Effects beyond 2048									3,248,788	196,328
TOTAL Utility Cost, Net CPW (2019$)									12,774,457	816,789
	Case 9 - Preferred, Storage and MiniGrid (RP1 Retires 12/2028; RP2 Lease Expires 12/2022)									
Cumulative Present Worth $000 (2019$)										
Utility CPW 2019-2029	5,517,178	2,296,150	185,947	308,198	1,131,086	748,301	259,958	6,817,693	3,629,125	4,528
Utility CPW 2019-2038	8,924,481	3,170,218	290,395	423,643	1,604,070	2,475,507	225,054	11,063,729	6,049,639	22,878
Utility CPW 2019-2048	11,415,922	3,766,943	394,054	451,629	1,888,778	4,112,069	148,931	13,239,036	8,939,290	34,082
CPW of End Effects beyond 2048									3,052,665	205
TOTAL Utility Cost, Net CPW (2019$)									11,991,955	34,287
	Case 12: High Renewables - Peaking									
Cumulative Present Worth $000 (2019$)										
Utility CPW 2019-2029	5,517,178	2,178,193	166,113	308,198	1,218,693	1,264,394	259,958	7,158,580	3,754,147	129,550
Utility CPW 2019-2038	8,924,481	2,466,042	169,467	423,643	1,807,263	4,040,215	225,054	11,964,993	6,091,171	64,410
Utility CPW 2019-2048	11,415,922	2,487,887	173,419	451,629	2,186,732	6,425,844	148,931	14,491,072	8,799,293	(105,915)
CPW of End Effects beyond 2048									2,685,436	(367,024)
TOTAL Utility Cost, Net CPW (2019$)									11,484,729	(472,939)

Figure 30 – Incremental Annual Cum. NPV Revenue Requirement to Base Optimization



5.3.3 Emissions Summary

Figure 31 provides insight to the emissions reductions over the planning period for the Preferred Plan and other optimized portfolios. These indicative reductions are results from actions undertaken as part of this IRP planning process. As illustrated, the Preferred Plan results in reductions from 2019 levels (baseline) of 65% for CO_2, and over 90% for NOx and SO_2 emissions by 2038[20].

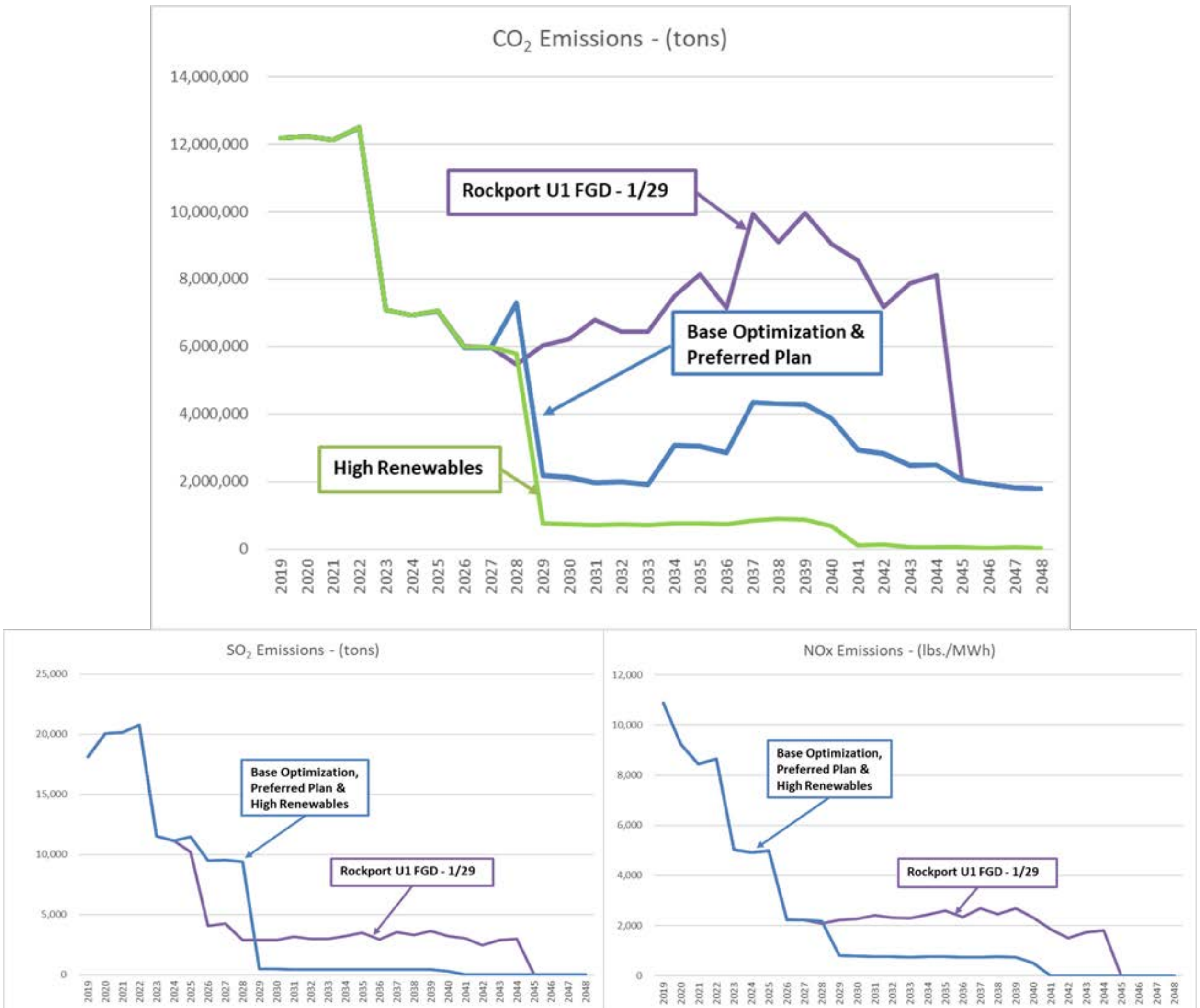


Figure 31. Emissions from Optimum Plans

[20] New gas resources added in the Preferred Plan are assumed to utilize Selective Catalyst Reduction (SCR) technology, which is considered Best Available Current Technology (BACT) to control NOx emissions.

5.4 Risk Analysis

In addition to comparing the Preferred Plan to the optimized portfolios under a variety of pricing assumptions, the Preferred Plan and an alternative portfolio were also evaluated using a stochastic, or "Monte Carlo" modeling technique where input variables are randomly selected from a universe of possible values, given certain standard deviation constraints and correlative relationships. This offers an additional approach by which to "test" the Preferred Plan over a distributed range of certain key variables. The output is, in turn, a distribution of possible outcomes, providing insight as to the risk or probability of a higher cost (revenue requirement) relative to the expected outcome.

This study included multiple risk iteration runs performed over the study period with key price variables (risk factors) being subjected to this stochastic-based risk analysis. The results take the form of a distribution of possible revenue requirement outcomes for each plan. Table 30 and Table 31 shows the input variables or risk factors within this IRP stochastic analysis and the historical correlative relationships to each other. Table 30 shows the input variables before carbon pricing (2019 to 2027) and Table 31 shows the input variables details after carbon pricing.

Table 30. Risk Analysis Factors & Their Relationships, 2019-2027

2019 - 2027	Natural GAS	Rockport-COAL	CO_2	Electricity
Natural GAS	1.00	-0.14	0.00	0.89
Rockport-COAL		1.00	0.00	-0.15
CO_2			0.00	0.00
Electricity				1.00
Avg Coeff of Variation	10.2%	3.2%	0.0%	7.0%

Table 31. Risk Analysis Factors & Their Relationships After Carbon Pricing, 2028-2038

2028 - 2038	Natural GAS	Rockport-COAL	CO_2	Electricity
Natural GAS	1.00	-0.67	0.91	0.68
Rockport-COAL		1.00	-0.72	-0.48
CO_2			1.00	0.67
Electricity				1.00
Avg Coeff of Variation	9.2%	9.3%	70.7%	12.4%

Comparing the Preferred Plan to alternative portfolios provides a data point that may be used to evaluate the risk associated with the Preferred Plan. The Company compared the Preferred Plan to the Case 1 – Base Optimization, Case 7 – Rockport U1 FGD in 2029 and Case 12 – High Renewables. Evaluating the optimal plans as a group allows I&M to determine if the resources in the Preferred Plan introduce more risk than relying on the least cost optimal plan. The range of values associated with the variable inputs is shown in Figure 32.

Figure 32. Range of Variable Inputs for Stochastic Analysis

5.4.1 Stochastic Modeling Process and Results

For each portfolio, the results of 100 random iterations are sorted from lowest cost to highest cost, with the differential between the median and higher percentile result from the multiple runs identified as Revenue Requirement at Risk (RRaR). For example, the 95th percentile is a level of required revenue sufficiently high that it will be exceeded, assuming the given plan is adopted, only five percent of the time. Thus, it is 95 percent likely that those higher-ends of revenue requirements would not be exceeded. The larger the RRaR, the greater the likelihood that customers could be subjected to higher costs relative to the portfolio's mean or expected cost. Conversely, there is equal likelihood that costs may be lower than the median value. These higher or lower costs are generally the result of the difference, or spread, between fuel prices and resultant PJM market energy prices. The greater that spread, the more "margin" is enjoyed by the Company and its customers.

Figure 33 illustrates the RRaR (expressed in terms of incremental cost over the 50th percentile).

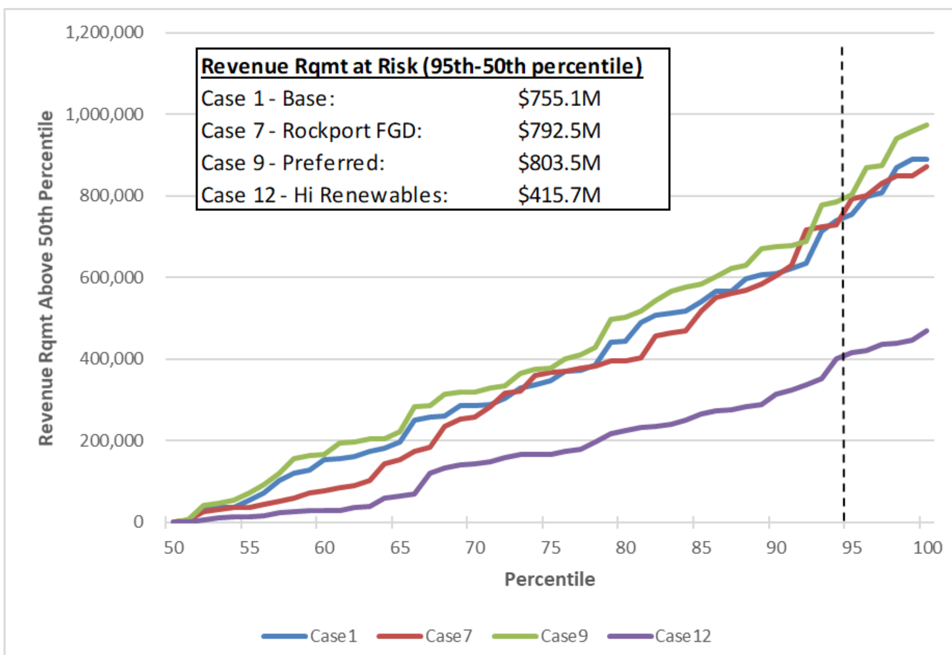


Figure 33. Revenue Requirement at Risk (RRaR) ($000) for Select Portfolios

The difference in RRaR between the portfolios analyzed is relatively small over the 100 simulations, with the Preferred Plan being slightly more risky by about $48.4M compared to the Base Plan, which suggests that the additional resources, specifically storage and "mini-grid" in the Preferred Plan does not introduce significant additional risk. While the lower RRaR of the

High Renewables plan indicates that the addition of renewable resources reduces revenue requirement risk, the analysis does not take into account, the aggressive build-out of these resources which may not be practical.

Based on the risk modeling performed, it is reasonable to conclude that the inherent risk characteristics of the Preferred Plan, which also includes a high level of renewable resources, represents a reasonable combination of expected costs and risk.

6.0 Conclusions and Short-Term Action Plan

6.1 Plan Summary

I&M used the modeling results to develop a Preferred Plan or "Plan". To arrive at the Preferred Plan, using Plexos®, I&M developed optimal portfolios with various options addressing I&M's capacity and energy resource needs over time under various commodity price and load conditions. In order to evaluate I&M's resource selection across varying commodity price and load conditions, twenty four (24) scenarios were analyzed for this IRP. The Preferred Plan balances cost and other factors to cost effectively meet I&M's demand and energy obligations while moving the Company toward a more diversified resource fleet.

Key components of I&M's Preferred Plan are as follows:

- Continue operation of the Cook units through the remainder of their current license periods;
- The Rockport Unit 2 lease expires at the end of 2022 and retire Rockport Unit 1 at the end of 2028;
- Continue deployment of supply-side renewable resource including the addition of over 3600 MW of wind and large scale solar by 2038, beginning in 2022;
- Incorporate 50MW of Batteries and 54MW of Micro/Mini-Grid resources by 2028;
- Add 2,700MW of Natural Gas Combined Cycle (NGCC) generation including 770 MW in 2028 to replace Rockport capacity, 770MW in 2034 to replace Cook Unit 1 and 1,155MW in 2037 to replace Cook Unit 2 at the end of their current license periods;
- Incorporates demand-side resources including 180MW of Energy Efficiency (EE) and Demand Response (DR) and
- Recognizes that residential and commercial customers will add distributed resources, primarily in the form of residential and commercial rooftop solar (i.e. Distributed Generation [DG]).

Figure 34 below shows I&M's assumed "going-in" capacity position (i.e. before resource additions) over the planning period, which uses the PJM summer peak to determine resource requirements. 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 1,762MW 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.

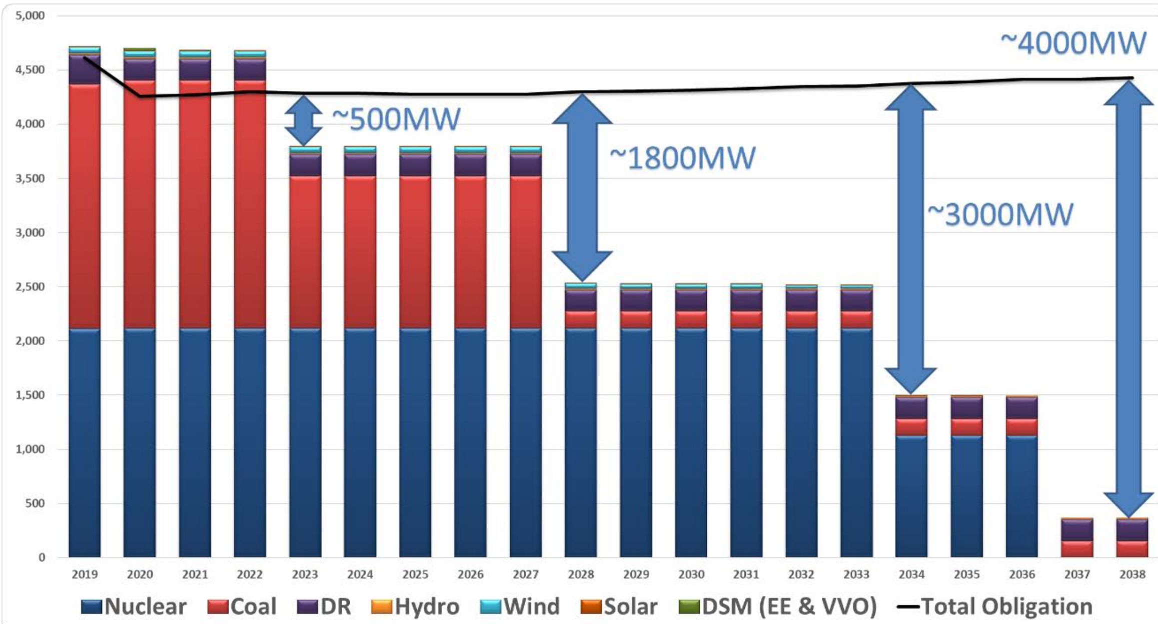


Figure 34. I&M "Going-In" Position

I&M has identified a diverse set of resources to address the capacity deficit position over the planning period. (Figure 35 and Table 32) These additions, which include solar, wind, natural gas, energy storage and energy efficiency resources along with STMP, are expected to eliminate the capacity deficit through the planning period. The solar resources are assumed to provide PJM capacity equal to 51.1% of their nameplate rating (or 102MW for 200MW of nameplate solar) and wind resources are assumed to provide PJM capacity equal to 12.3% of their nameplate rating (or 37MW for 300 MW of nameplate wind).

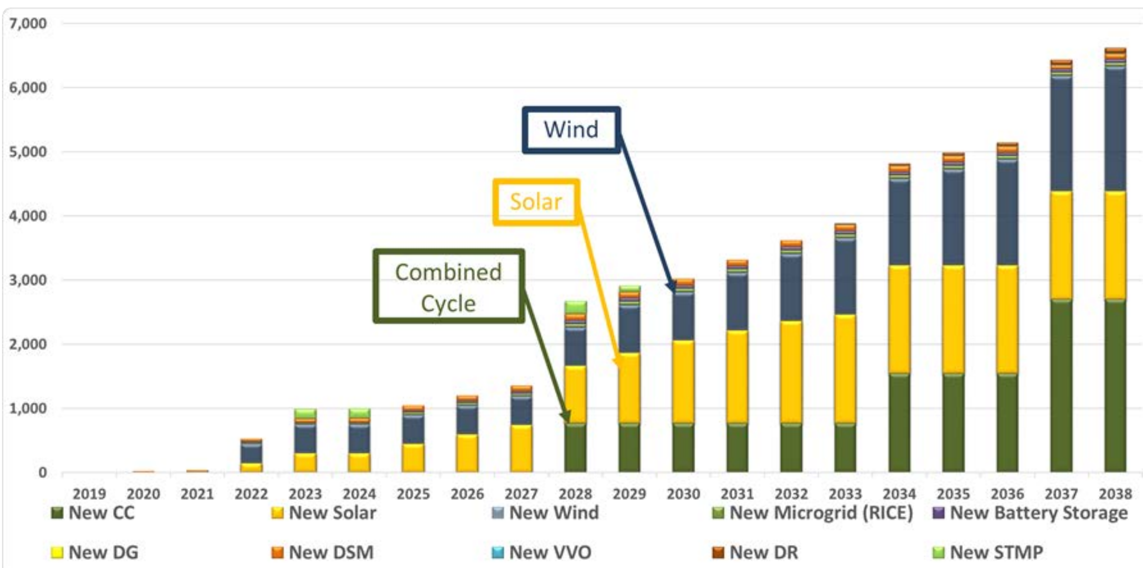


Figure 35. I&M New Capacity Additions – Nameplate (MW)

The resource additions allow I&M to satisfy its PJM load obligations over the planning period. Additionally, EECO and customer owned generation such as rooftop solar will also improve I&M's capacity position.

	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*
		New Wind Firm				37	55	55	55	55	55	74	92	92	111	129	148	166	185	203	221	240
		New Wind				*300*	*450*	*450*	*450*	*450*	*450*	*600*	*750*	*750*	*900*	*1050*	*1200*	*1350*	*1500*	*1650*	*1800*	*1950*
		New DG Firm				10	12	15	16	17	17	19	20	22	24	25	28	30	31	33	35	36
		New Microgrid (RICE)				18	18	18	36	36	36	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*
		New VVO															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
		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

A summary of the Preferred Plan costs and levelized customer bill impacts[21] relative to the Base plan and various alternative plans is shown in Table 33. Notably, the Preferred Plan is a flexible, balanced low cost plan over the 20-year IRP planning period, and moves the Company toward a more diversified resource fleet. This is accomplished by adding smaller, geographically diverse resources consisting of solar, wind, DSM, energy storage, microgrids and STMP during the first several years of the plan.

Table 33. Preferred Plan cost comparison to alternative plans

	Cummulative Present Worth Cost over Case 1 ($000)		Levelized Annual Bill Impact over Case 1 ($)	
	11 yr	20 yr	11 yr	20 yr
Case 1 - Base Optimization	-	-	-	-
Case 9 - Preferred Plan	$ 4,528	$ 22,878	$ 0.33	$ 1.16
Case 12 - High Renewables	$ 129,550	$ 64,410	$ 9.38	$ 3.38
Case 7 - Rockport U1 FGD 1/2029	$ 38,034	$ 684,774	$ 2.73	$ 34.82

Furthermore, as Figure 36 shows, the Preferred Plan results in reductions from 2019 levels (baseline) of 65% for CO_2, and over 90% for NOx and SO_2 emissions by 2038.

[21]The Levelized Annual Bill Impact is an indicative estimate of the incremental cost compared to Case 1 – Base Optimization. This indicative estimate is only capturing the costs and benefits related to the proposed resource additions included in this IRP. The estimate assumes the impact to an "Average Customer" using 12,000 kWh/year.

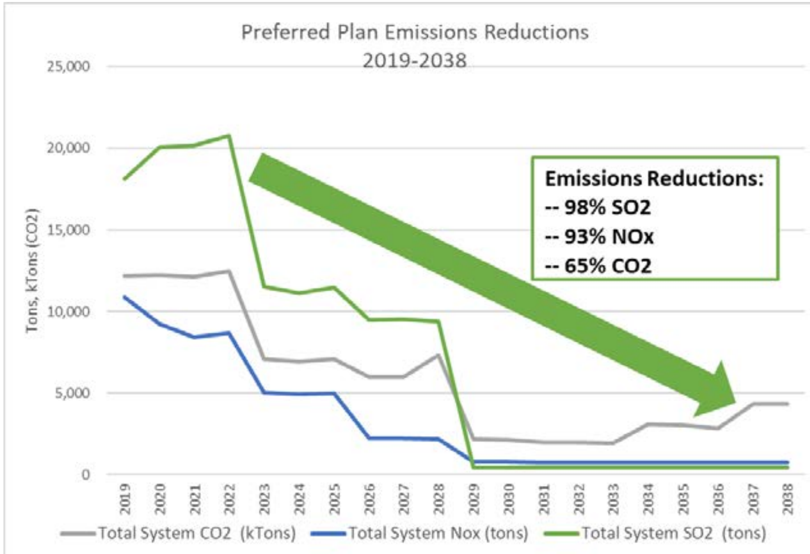


Figure 36. Preferred Plan Emissions Reductions

The IRP process is a continuous activity; assumptions and plans are reviewed as new information becomes available and modified as appropriate. Indeed, the resource portfolios developed herein reflect, to a large extent, assumptions that are subject to change; an IRP is simply a snapshot of the future at a given time. As noted previously, this IRP is not a commitment to specific resource additions or other courses of action, as the future is highly uncertain. The resource planning process continues to be complex, especially with regard to such things as pending regulatory restrictions, technology advancement, changing energy supply pricing fundamentals, uncertainty of demand and end-use efficiency improvements. These complexities exacerbate the need for flexibility and adaptability in any ongoing planning activity and resource planning process.

6.1.1 I&M Short-Term Action Plan

While the I&M IRP is regularly reviewed and modified as assumptions, scenarios, and sensitivities are examined and tested based upon new information that becomes available, I&M intends to pursue the following activities for the 2018-19 IRP Short-Term action plan:

1. Continue the evaluation of the Company's options related to Rockport Operations.
2. Continue the evaluation of the integration of battery and micro-grid technology.

3. Continue the planning and regulatory actions necessary to implement additional economic EE programs in Indiana and Michigan.
4. Continue to monitor market prices for renewable resources, particularly wind and solar, and if economically advantageous, pursue competitive solicitations that would include self-build or acquisition options.
5. Monitor developments associated with PJM's Capacity Performance rule.
6. Monitor the status of, and participate in formulating any proposed carbon emissions regulations. Once established, assess the implications of such regulations on I&M's resource profile.
7. Be in a position to adjust this action plan and future IRPs to reflect changing circumstances.

In conjunction with the Company's short-term action plan, the Preferred Plan offers I&M significant flexibility should future conditions differ considerably from the assumptions underpinning the Preferred Plan. With the current assumptions made for the Preferred Plan, however, the associated costs are shown in Exhibit C (Case 9).

Since the Company's last IRP in 2015, I&M accomplishments towards the Short-Term Action plan included:

- The Company has successfully planned, implemented, and evaluated a portfolio of cost effective DSM/EE programs in both Indiana and Michigan. I&M has filed annual performance, both energy savings and budget adherence and management, with the Commission each year as part of its annual DSM Rider reconciliation process where verified results and actual cost have been presented against plan targets in each respective year and as authorized by the Commission. Furthermore, the Company completed a Market Potential Study during 2016 that assessed the potential for DSM/EE over a twenty year forecast period and has used the results of that study in this IRP.

- As discussed in Section 3.3.2, the Company is actively monitoring rulemaking activities related to the proposed Affordable Clean Energy (ACE) rule to replace the CPP with new emission guidelines for regulating CO2 from existing sources.

6.2 Conclusion

This IRP presents various plans, including the Preferred Plan that would provide adequate capacity resources at reasonable cost, through a combination of supply-side resources and demand-side programs throughout the planning period.

The Preferred Plan includes incremental resources that will provide—in addition to the needed PJM installed capacity to achieve mandatory PJM (summer) peak demand requirements—modest amounts of additional energy to reduce the long-term exposure of the Company’s customers to PJM energy markets.

The resource portfolios reflect, largely, assumptions that are subject to change; an IRP is simply a snapshot of the future at a given time. As noted previously, this IRP is not a commitment to specific resource additions or other courses of action. The resource planning process continues to be complex, especially with regard to such things as technology advancement, changing energy supply pricing fundamentals, uncertainty of demand and end-use efficiency improvements. These complexities exacerbate the need for flexibility and adaptability in any ongoing planning activity and resource planning process.

Appendix Vol. 1 – Included In Hard Copy

Exhibit A	Load Forecast Tables
Exhibit B	IRP Public Summary Document
Exhibit C	Case and Scenario Results
Exhibit D	New Generation Resources
Exhibit E	I&M Internal Hourly Load Data
Exhibit F	Stakeholder Process Exhibits
Exhibit G	Cross Reference Table

Exhibit A Load Forecast Tables

Exhibit A-1

Indiana Michigan Power Company
Annual Internal Energy Requirements and Growth Rates
2009-2038

	Residential Sales		Commercial Sales		Industrial Sales		Other Internal Sales		Losses		Total Internal Energy Requirements	
Year	GWH	% Growth	GWH	% Growth	GWH	% Growth	GWH	% Growth	GWH	% Growth	GWH	% Growth
Actual												
2009	5,767	---	5,038	---	6,762	---	4,628	---	2,102	---	24,297	---
2010	6,083	5.5	5,121	1.6	7,445	10.1	4,887	5.6	2,294	9.1	25,829	6.3
2011	5,997	-1.4	5,045	-1.5	7,523	1.0	4,975	1.8	2,388	4.1	25,929	0.4
2012	5,771	-3.8	5,001	-0.9	7,556	0.4	5,112	2.8	2,290	-4.1	25,731	-0.8
2013	5,778	0.1	4,943	-1.2	7,522	-0.5	5,103	-0.2	2,374	3.6	25,719	0.0
2014	5,776	0.0	4,884	-1.2	7,640	1.6	5,103	0.0	2,339	-1.5	25,741	0.1
2015	5,483	-5.1	4,891	0.2	7,570	-0.9	5,033	-1.4	2,069	-11.5	25,047	-2.7
2016	5,578	1.7	4,979	1.8	7,780	2.8	5,121	1.8	1,949	-5.8	25,407	1.4
2017	5,311	-4.8	4,785	-3.9	7,781	0.0	5,032	-1.7	1,837	-5.8	24,745	-2.6
2018	5,731	7.9	4,852	1.4	7,836	0.7	4,678	-7.0	1,907	3.8	25,003	1.0
Forecast												
2019*	5,351	-6.6	4,776	-1.6	7,847	0.1	4,579	-2.1	1,938	1.6	24,491	-2.0
2020	5,261	-1.7	4,691	-1.8	7,748	-1.3	3,655	-20.2	1,924	-0.7	23,281	-4.9
2021	5,177	-1.6	4,631	-1.3	7,806	0.7	3,057	-16.4	1,873	-2.7	22,544	-3.2
2022	5,157	-0.4	4,629	-0.1	7,945	1.8	3,059	0.1	1,867	-0.3	22,657	0.5
2023	5,163	0.1	4,642	0.3	7,937	-0.1	3,064	0.2	1,879	0.6	22,686	0.1
2024	5,189	0.5	4,667	0.6	7,894	-0.5	3,068	0.1	1,882	0.1	22,700	0.1
2025	5,222	0.6	4,672	0.1	7,918	0.3	3,075	0.2	1,879	-0.1	22,765	0.3
2026	5,220	0.0	4,651	-0.4	7,935	0.2	3,080	0.2	1,882	0.1	22,768	0.0
2027	5,214	-0.1	4,633	-0.4	7,939	0.1	3,086	0.2	1,882	0.0	22,754	-0.1
2028	5,211	-0.1	4,621	-0.3	7,992	0.7	3,095	0.3	1,884	0.1	22,802	0.2
2029	5,219	0.2	4,612	-0.2	8,050	0.7	3,103	0.3	1,890	0.3	22,874	0.3
2030	5,223	0.1	4,589	-0.5	8,088	0.5	3,111	0.2	1,891	0.1	22,902	0.1
2031	5,238	0.3	4,570	-0.4	8,136	0.6	3,119	0.3	1,893	0.1	22,957	0.2
2032	5,250	0.2	4,555	-0.3	8,187	0.6	3,127	0.3	1,897	0.2	23,017	0.3
2033	5,258	0.2	4,543	-0.3	8,245	0.7	3,136	0.3	1,900	0.1	23,082	0.3
2034	5,268	0.2	4,532	-0.2	8,303	0.7	3,146	0.3	1,904	0.2	23,152	0.3
2035	5,280	0.2	4,523	-0.2	8,349	0.6	3,155	0.3	1,911	0.4	23,218	0.3
2036	5,296	0.3	4,515	-0.2	8,382	0.4	3,163	0.3	1,915	0.2	23,270	0.2
2037	5,309	0.3	4,508	-0.1	8,413	0.4	3,171	0.3	1,917	0.1	23,318	0.2
2038	5,325	0.3	4,504	-0.1	8,448	0.4	3,179	0.3	1,920	0.1	23,377	0.2

*Includes 3 months actual and 9 months forecast data.

Average Annual Growth Rates												
2009-2018		-0.1		-0.4		1.7		0.1		-1.1		0.3
2019-2038		0.0		-0.3		0.4		-1.9		-0.1		-0.2

Exhibit A-2 a

Indiana Michigan Power Company-Indiana
Annual Internal Energy Requirements and Growth Rates
2009-2038

Year	Residential Sales GWH	Residential Sales % Growth	Commercial Sales GWH	Commercial Sales % Growth	Industrial Sales GWH	Industrial Sales % Growth	Other Internal Sales GWH	Other Internal Sales % Growth	Losses GWH	Losses % Growth	Total Internal Energy Requirements GWH	Total Internal Energy Requirements % Growth
Actual												
2009	4,548	---	4,234	---	5,977	---	4,052	---	1,408	---	20,220	---
2010	4,806	5.7	4,305	1.7	6,593	10.3	4,261	5.2	1,686	19.8	21,652	7.1
2011	4,750	-1.2	4,240	-1.5	6,727	2.0	4,352	2.1	1,744	3.5	21,814	0.7
2012	4,553	-4.1	4,183	-1.3	6,755	0.4	4,477	2.9	1,713	-1.8	21,681	-0.6
2013	4,564	0.2	4,134	-1.2	6,709	-0.7	4,483	0.1	1,713	0.0	21,603	-0.4
2014	4,556	-0.2	4,090	-1.1	6,809	1.5	4,479	-0.1	1,660	-3.1	21,594	0.0
2015	4,314	-5.3	4,086	-0.1	6,729	-1.2	4,412	-1.5	1,365	-17.7	20,906	-3.2
2016	4,392	1.8	4,151	1.6	6,948	3.3	4,487	1.7	1,148	-16.0	21,127	1.1
2017	4,165	-5.2	3,977	-4.2	6,965	0.2	4,422	-1.4	1,038	-9.5	20,568	-2.6
2018	4,510	8.3	4,042	1.6	7,018	0.8	4,055	-8.3	1,581	52.2	21,205	3.1
Forecast												
2019*	4,180	-7.3	3,976	-1.6	7,016	0.0	3,966	-2.2	1,674	5.9	20,812	-1.8
2020	4,104	-1.8	3,893	-2.1	6,917	-1.4	3,373	-15.0	1,622	-3.1	19,909	-4.3
2021	4,033	-1.7	3,838	-1.4	6,971	0.8	2,980	-11.7	1,587	-2.2	19,409	-2.5
2022	4,016	-0.4	3,833	-0.1	7,114	2.0	2,982	0.1	1,585	-0.2	19,529	0.6
2023	4,024	0.2	3,848	0.4	7,109	-0.1	2,987	0.2	1,597	0.7	19,565	0.2
2024	4,050	0.7	3,873	0.7	7,062	-0.7	2,991	0.1	1,598	0.1	19,575	0.1
2025	4,083	0.8	3,878	0.1	7,083	0.3	2,997	0.2	1,597	-0.1	19,639	0.3
2026	4,083	0.0	3,860	-0.5	7,101	0.2	3,003	0.2	1,600	0.2	19,647	0.0
2027	4,080	-0.1	3,846	-0.4	7,104	0.0	3,009	0.2	1,600	0.0	19,638	0.0
2028	4,078	0.0	3,836	-0.3	7,154	0.7	3,017	0.3	1,602	0.2	19,688	0.3
2029	4,088	0.2	3,828	-0.2	7,210	0.8	3,026	0.3	1,608	0.4	19,760	0.4
2030	4,092	0.1	3,809	-0.5	7,248	0.5	3,034	0.3	1,610	0.1	19,792	0.2
2031	4,106	0.3	3,794	-0.4	7,294	0.6	3,042	0.3	1,612	0.1	19,847	0.3
2032	4,116	0.2	3,781	-0.3	7,343	0.7	3,050	0.3	1,616	0.2	19,906	0.3
2033	4,123	0.2	3,771	-0.3	7,399	0.8	3,060	0.3	1,619	0.2	19,972	0.3
2034	4,134	0.3	3,762	-0.2	7,456	0.8	3,069	0.3	1,624	0.3	20,045	0.4
2035	4,147	0.3	3,755	-0.2	7,501	0.6	3,078	0.3	1,630	0.4	20,111	0.3
2036	4,163	0.4	3,749	-0.2	7,533	0.4	3,087	0.3	1,635	0.3	20,166	0.3
2037	4,178	0.3	3,744	-0.1	7,563	0.4	3,095	0.3	1,637	0.2	20,217	0.3
2038	4,194	0.4	3,741	-0.1	7,599	0.5	3,104	0.3	1,640	0.2	20,277	0.3

*Includes 3 months actual and 9 months forecast data.

Average Annual Growth Rates

	Residential Sales % Growth	Commercial Sales % Growth	Industrial Sales % Growth	Other Internal Sales % Growth	Losses % Growth	Total Internal Energy Requirements % Growth
2009-2018	-0.1	-0.5	1.8	0.0	1.3	0.5
2019-2038	0.0	-0.3	0.4	-1.3	-0.1	-0.1

Exhibit A-2 b

Indiana Michigan Power Company-Michigan
Annual Internal Energy Requirements and Growth Rates
2009-2038

Year	Residential Sales GWH	Residential Sales % Growth	Commercial Sales GWH	Commercial Sales % Growth	Industrial Sales GWH	Industrial Sales % Growth	Other Internal Sales GWH	Other Internal Sales % Growth	Losses GWH	Losses % Growth	Total Internal Energy Requirements GWH	Total Internal Energy Requirements % Growth
Actual												
2009	1,218	---	804	---	785	---	576	---	694	---	4,077	---
2010	1,277	4.8	816	1.4	852	8.5	626	8.6	608	-12.5	4,178	2.5
2011	1,248	-2.3	805	-1.3	796	-6.6	623	-0.4	644	5.9	4,114	-1.5
2012	1,217	-2.4	818	1.7	802	0.8	635	1.9	577	-10.3	4,050	-1.6
2013	1,215	-0.2	809	-1.1	813	1.4	619	-2.5	660	14.3	4,116	1.6
2014	1,219	0.4	794	-1.9	831	2.2	624	0.8	679	2.8	4,147	0.8
2015	1,169	-4.2	806	1.5	841	1.2	621	-0.5	704	3.7	4,140	-0.2
2016	1,186	1.4	828	2.8	831	-1.1	634	2.0	802	13.9	4,280	3.4
2017	1,145	-3.4	808	-2.4	816	-1.8	609	-3.8	798	-0.5	4,177	-2.4
2018	1,221	6.6	810	0.2	818	0.3	623	2.3	326	-59.1	3,799	-9.1
Forecast												
2019*	1,171	-4.1	800	-1.2	831	1.6	612	-1.8	264	-19.2	3,678	-3.2
2020	1,157	-1.2	798	-0.3	831	0.0	283	-53.8	302	14.6	3,371	-8.3
2021	1,144	-1.1	793	-0.6	835	0.4	77	-72.7	285	-5.5	3,134	-7.0
2022	1,141	-0.3	795	0.3	831	-0.4	77	0.3	283	-1.0	3,127	-0.2
2023	1,139	-0.1	793	-0.2	828	-0.4	77	0.1	283	0.1	3,121	-0.2
2024	1,139	0.0	794	0.1	832	0.5	77	0.0	283	0.1	3,125	0.1
2025	1,139	0.0	794	0.0	834	0.3	77	0.0	282	-0.4	3,126	0.0
2026	1,136	-0.2	791	-0.4	834	0.0	77	0.0	282	-0.2	3,120	-0.2
2027	1,134	-0.2	787	-0.4	835	0.1	77	0.0	282	0.0	3,116	-0.1
2028	1,133	-0.2	785	-0.3	837	0.3	77	-0.1	282	0.0	3,114	-0.1
2029	1,132	-0.1	784	-0.2	839	0.3	77	-0.1	282	-0.1	3,114	0.0
2030	1,131	-0.1	780	-0.5	841	0.2	77	-0.1	281	-0.2	3,110	-0.1
2031	1,133	0.2	777	-0.4	843	0.2	77	-0.2	281	-0.1	3,110	0.0
2032	1,134	0.1	774	-0.3	844	0.2	77	-0.3	281	0.1	3,111	0.0
2033	1,135	0.1	772	-0.3	846	0.2	77	-0.3	281	-0.2	3,110	0.0
2034	1,134	-0.1	770	-0.3	847	0.1	76	-0.3	281	0.0	3,108	-0.1
2035	1,133	-0.1	768	-0.2	848	0.1	76	-0.3	281	0.0	3,106	0.0
2036	1,133	-0.1	766	-0.2	849	0.1	76	-0.3	280	-0.1	3,104	-0.1
2037	1,132	-0.1	765	-0.2	849	0.1	76	-0.3	280	-0.2	3,101	-0.1
2038	1,131	0.0	764	-0.2	850	0.0	75	-0.3	279	-0.2	3,099	-0.1

*Includes 3 months actual and 9 months forecast data.

Average Annual Growth Rates	Residential Sales % Growth	Commercial Sales % Growth	Industrial Sales % Growth	Other Internal Sales % Growth	Losses % Growth	Total Internal Energy Requirements % Growth
2009-2018	0.0	0.1	0.5	0.9	-8.1	-0.8
2019-2038	-0.2	-0.2	0.1	-10.4	0.3	-0.9

Exhibit A-3

Indiana Michigan Power Company
Composition of Forecast of Other Internal Sales (GWh)
2019-2038

	Indiana			Michigan			Total Company		
Year	Street Lighting	Wholesale	Total	Street Lighting	Wholesale	Total	Street Lighting	Wholesale	Total
2019	59	3,907	3,966	11	602	612	69	4,509	4,579
2020	59	3,313	3,373	10	272	283	70	3,586	3,655
2021	59	2,921	2,980	10	67	77	69	2,988	3,057
2022	59	2,923	2,982	10	67	77	69	2,990	3,059
2023	59	2,928	2,987	10	67	77	69	2,996	3,064
2024	59	2,932	2,991	10	67	77	69	3,000	3,068
2025	59	2,938	2,997	10	68	77	69	3,006	3,075
2026	59	2,944	3,003	10	68	77	69	3,012	3,080
2027	59	2,950	3,009	10	68	77	68	3,018	3,086
2028	59	2,959	3,017	9	68	77	68	3,026	3,095
2029	59	2,967	3,026	9	68	77	68	3,035	3,103
2030	59	2,975	3,034	9	68	77	68	3,043	3,111
2031	59	2,983	3,042	9	68	77	68	3,051	3,119
2032	59	2,992	3,050	9	68	77	68	3,059	3,127
2033	59	3,001	3,060	9	68	77	68	3,068	3,136
2034	59	3,010	3,069	9	67	76	68	3,078	3,146
2035	59	3,019	3,078	9	67	76	68	3,087	3,155
2036	59	3,028	3,087	9	67	76	68	3,095	3,163
2037	59	3,036	3,095	9	67	76	68	3,103	3,171
2038	59	3,045	3,104	9	67	75	68	3,112	3,179

Exhibit A-4

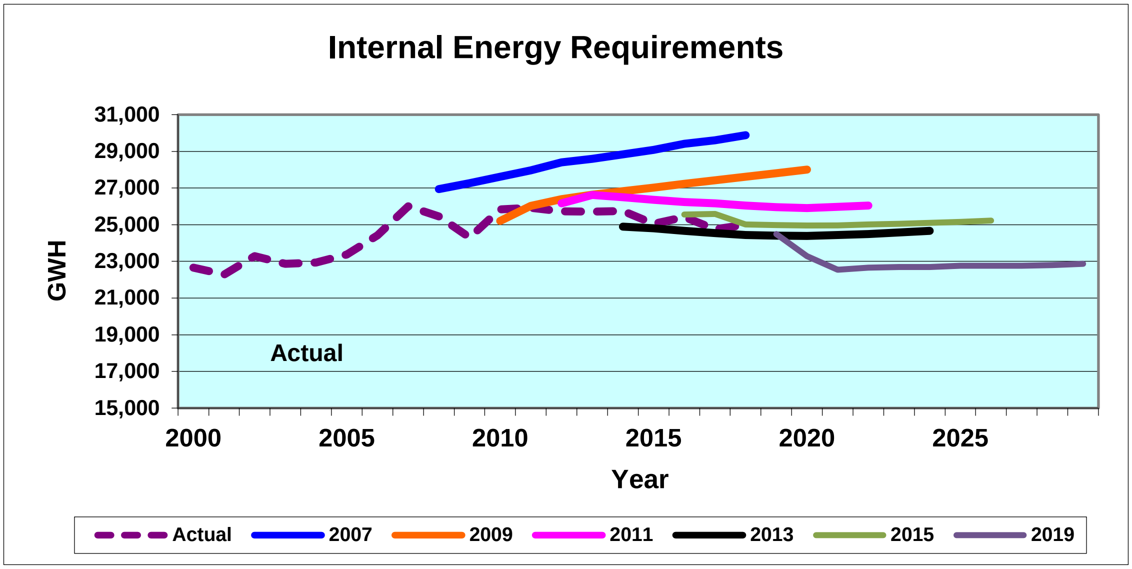
Indiana Michigan Power Company
Seasonal and Annual Peak Internal Demands, Energy Requirements and Load Factor
2009-2038

	Summer Peak			Preceding Winter Peak			Annual Peak, Energy and Load Factor				
	Date	MW	% Growth	Date	MW	% Growth	MW	% Growth	GWH	% Growth	Load Factor %
Actual											
2009	06/25/09	4,262	---	01/15/09	3,728	---	4,262	---	24,297	---	65.1
2010	07/23/10	4,474	5.0	12/10/09	3,858	3.5	4,474	5.0	25,829	6.3	65.9
2011	07/21/11	4,837	8.1	12/13/10	3,785	-1.9	4,837	8.1	25,929	0.4	61.2
2012	07/06/12	4,726	-2.3	01/20/12	3,686	-2.6	4,726	-2.3	25,731	-0.8	62.0
2013	09/10/13	4,540	-3.9	01/22/13	3,782	2.6	4,540	-3.9	25,719	0.0	64.7
2014	09/05/14	4,388	-3.4	01/22/14	3,938	4.1	4,388	-3.4	25,741	0.1	67.0
2015	07/28/15	4,398	0.2	01/14/15	3,952	0.4	4,398	0.2	25,047	-2.7	65.0
2016	08/11/16	4,547	3.4	01/13/16	3,702	-6.3	4,547	3.4	25,407	1.4	63.6
2017	07/19/17	4,230	-7.0	12/15/16	3,795	2.5	4,230	-7.0	24,745	-2.6	66.8
2018	06/18/18	4,369	3.3	01/16/18	3,723	-1.9	4,369	3.3	25,003	1.0	65.3
Forecast											
2019*		4,398	0.7		3,770	1.3	4,390	0.5	24,491	-2.0	63.7
2020		4,012	-8.8		3,582	-5.0	4,012	-8.6	23,281	-4.9	66.1
2021		4,006	-0.1		3,362	-6.2	4,006	-0.1	22,544	-3.2	64.2
2022		4,026	0.5		3,378	0.5	4,026	0.5	22,657	0.5	64.2
2023		4,029	0.1		3,381	0.1	4,029	0.1	22,686	0.1	64.3
2024		4,050	0.5		3,395	0.4	4,050	0.5	22,700	0.1	63.8
2025		4,051	0.0		3,412	0.5	4,051	0.0	22,765	0.3	64.1
2026		4,053	0.0		3,413	0.0	4,053	0.0	22,768	0.0	64.1
2027		4,052	0.0		3,410	-0.1	4,052	0.0	22,754	-0.1	64.1
2028		4,074	0.5		3,418	0.3	4,074	0.5	22,802	0.2	63.7
2029		4,080	0.1		3,412	-0.2	4,080	0.1	22,874	0.3	64.0
2030		4,088	0.2		3,415	0.1	4,088	0.2	22,902	0.1	64.0
2031		4,100	0.3		3,423	0.2	4,100	0.3	22,957	0.2	63.9
2032		4,122	0.6		3,430	0.2	4,122	0.6	23,017	0.3	63.6
2033		4,126	0.1		3,437	0.2	4,126	0.1	23,082	0.3	63.9
2034		4,147	0.5		3,433	-0.1	4,147	0.5	23,152	0.3	63.7
2035		4,160	0.3		3,442	0.2	4,160	0.3	23,218	0.3	63.7
2036		4,183	0.6		3,450	0.2	4,183	0.6	23,270	0.2	63.3
2037		4,183	0.0		3,455	0.2	4,183	0.0	23,318	0.2	63.6
2038		4,196	0.3		3,463	0.2	4,196	0.3	23,377	0.2	63.6

*Total energy requirements reflect 3 months actual and 9 months forecast data.

Exhibit A-5

INDIANA MICHIGAN POWER COMPANY
COMPARISON OF FORECASTS



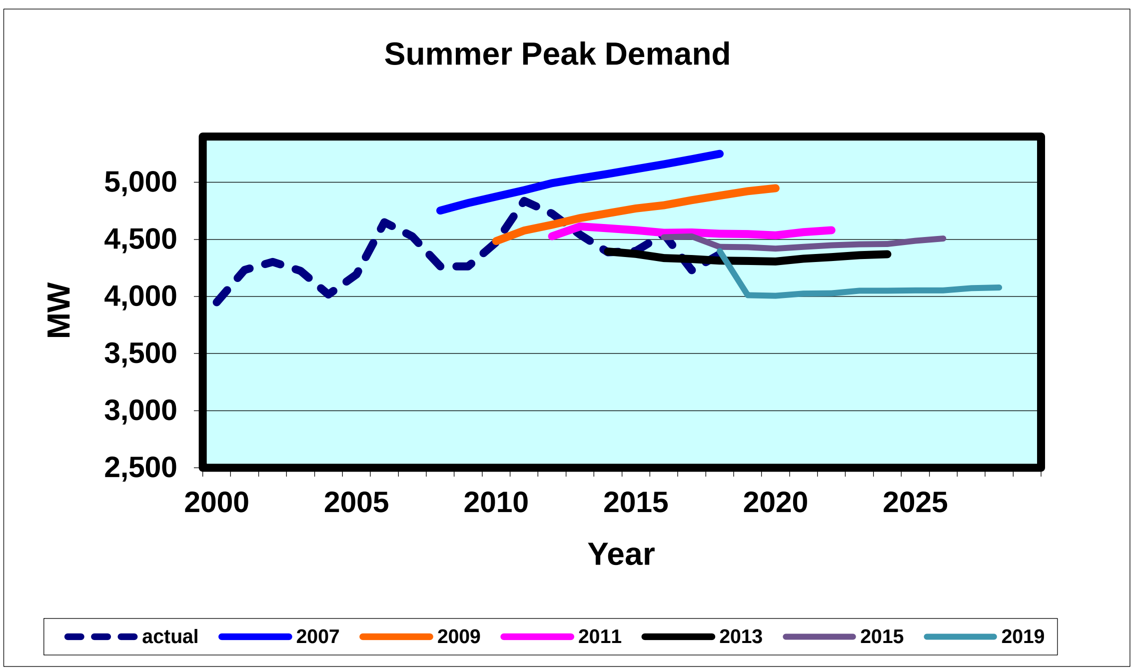


Exhibit A-6

Indiana Michigan Power Company
Profiles of Monthly Peak Internal Demands
2008, 2013, 2018 (Actual)
2028 and 2038

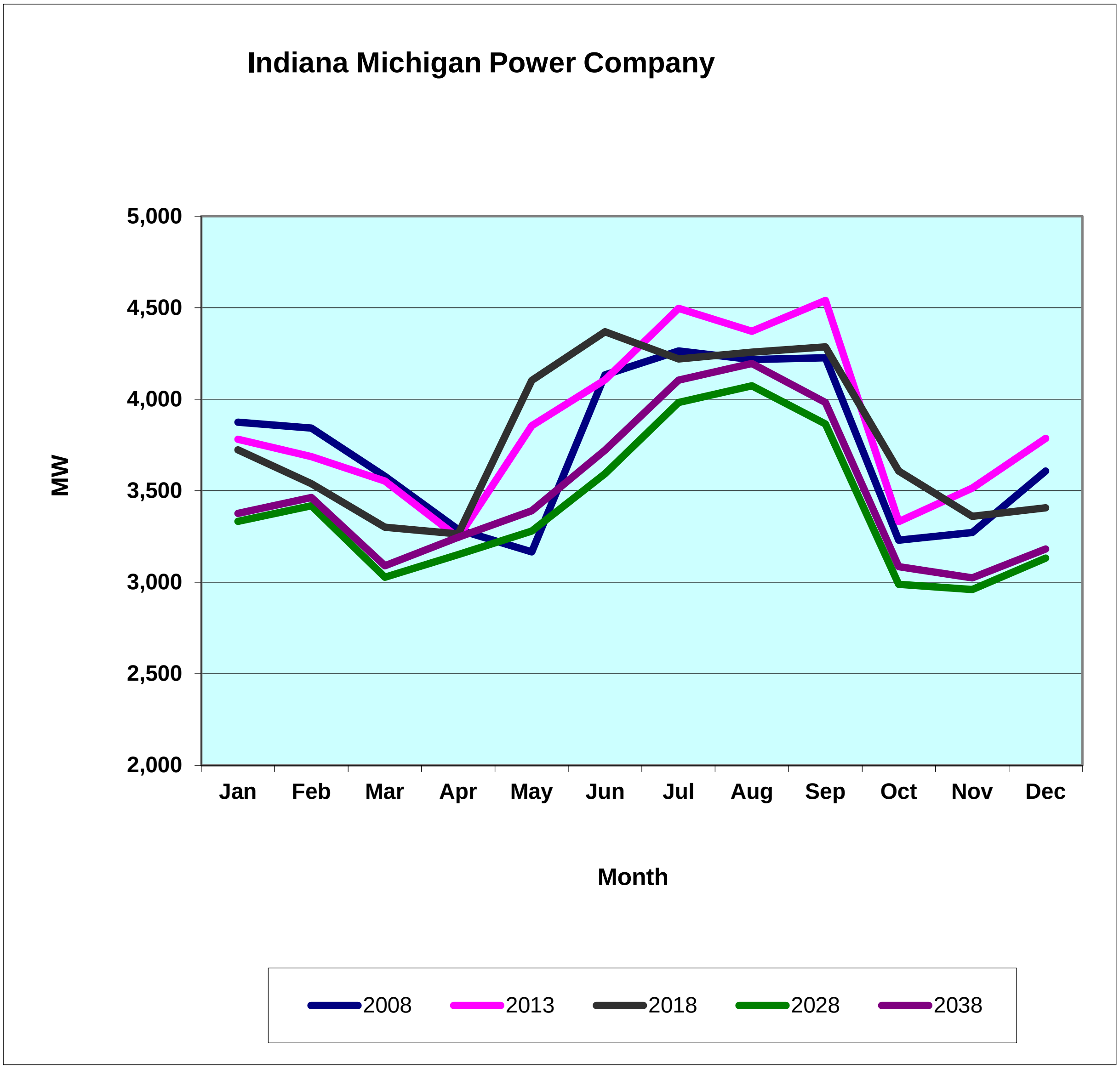
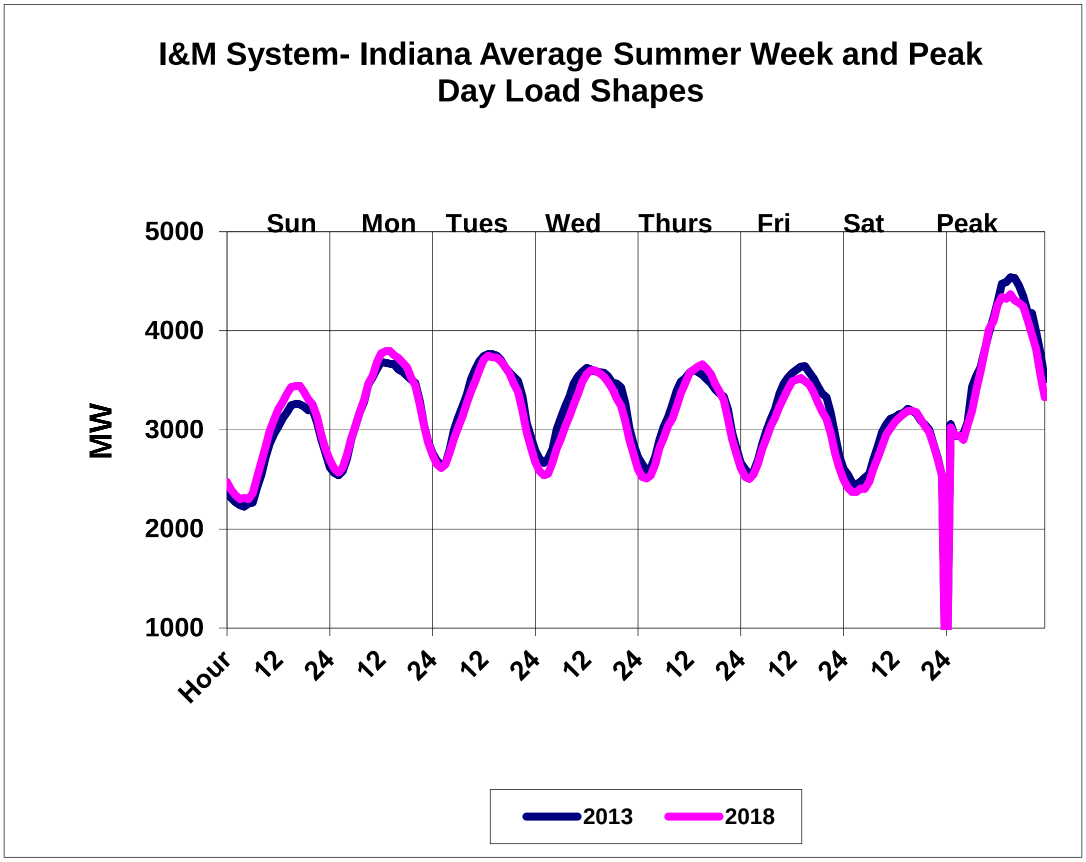


Exhibit A-7


I&M System- Indiana Average Summer Week and Peak Day Load Shapes
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Thurs
Fri
Sat
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3000
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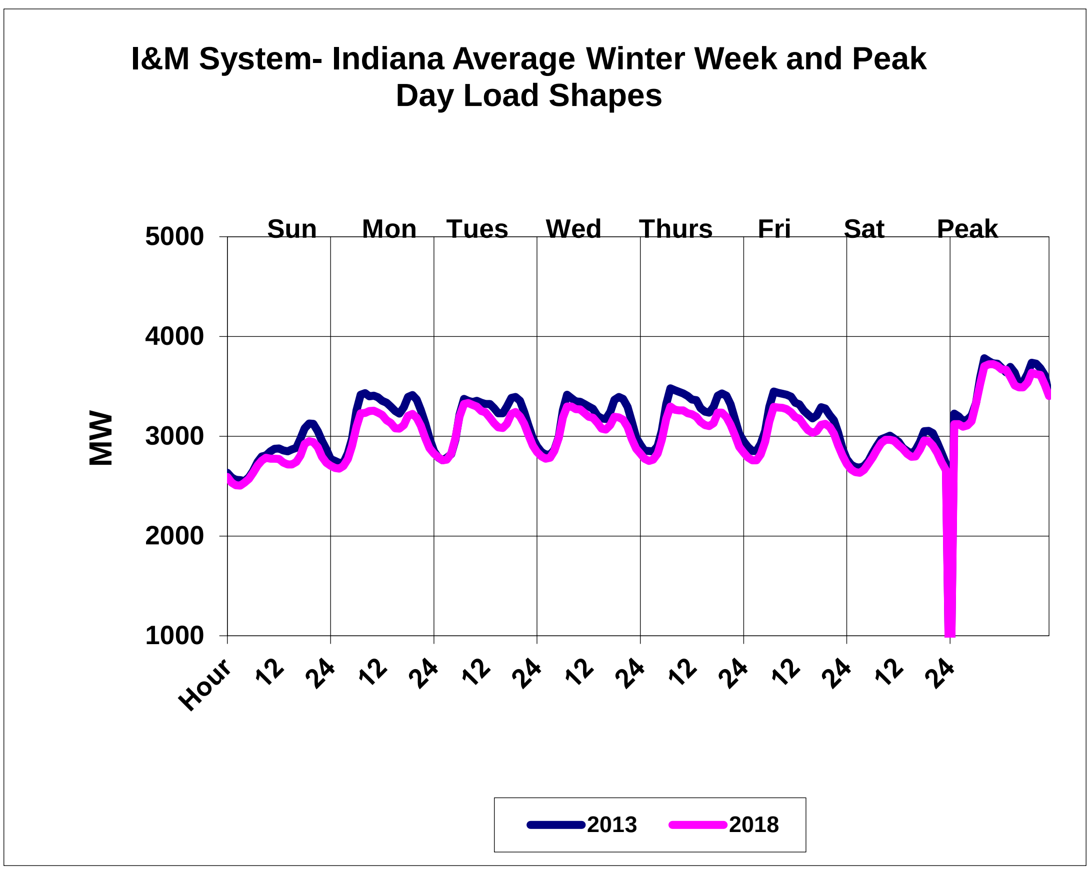
24
2013
2018


I&M System- Indiana Average Winter Week and Peak Day Load Shapes
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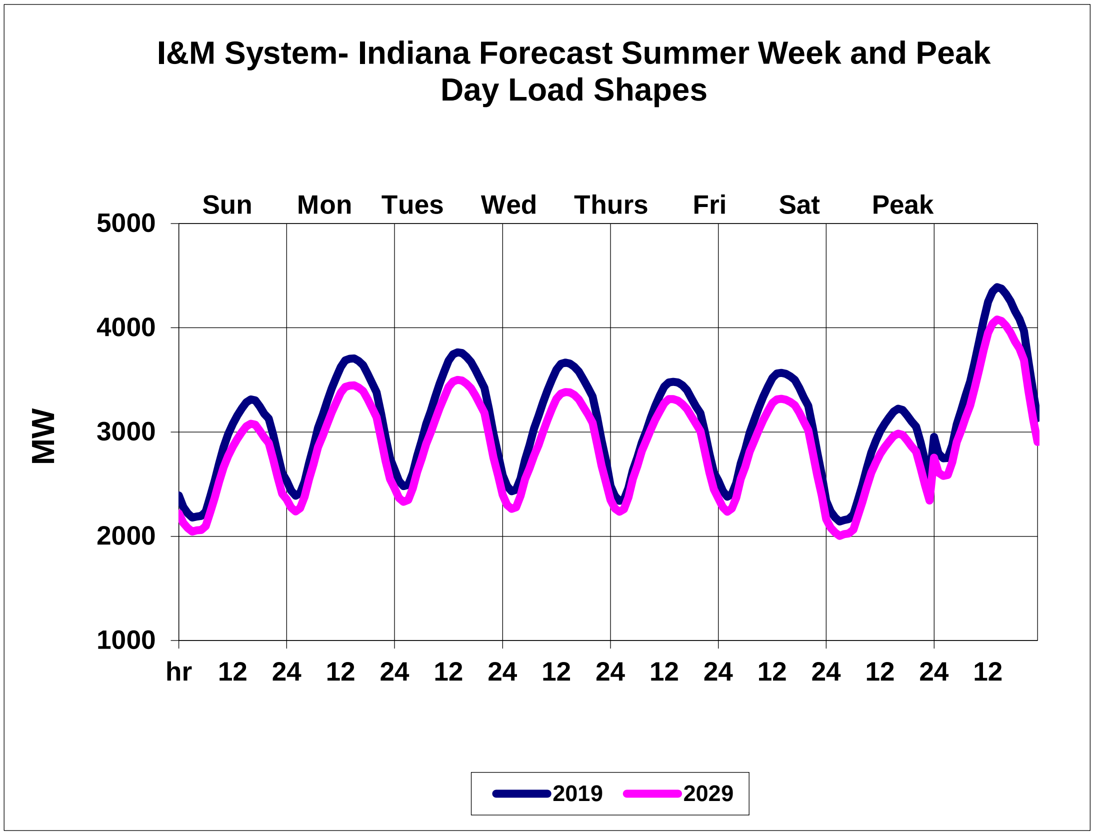
2013
2018

Exhibit A-8


I&M System- Indiana Forecast Summer Week and Peak Day Load Shapes
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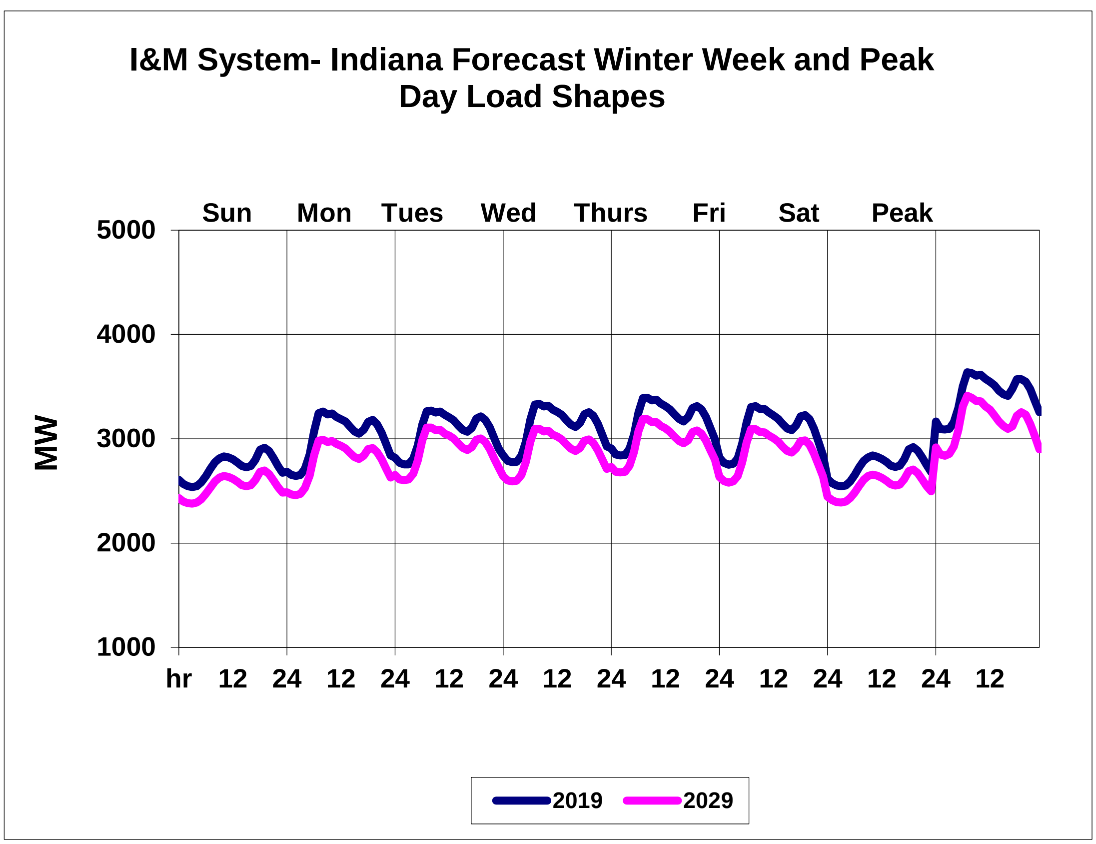
I&M System- Indiana Forecast Winter Week and Peak Day Load Shapes
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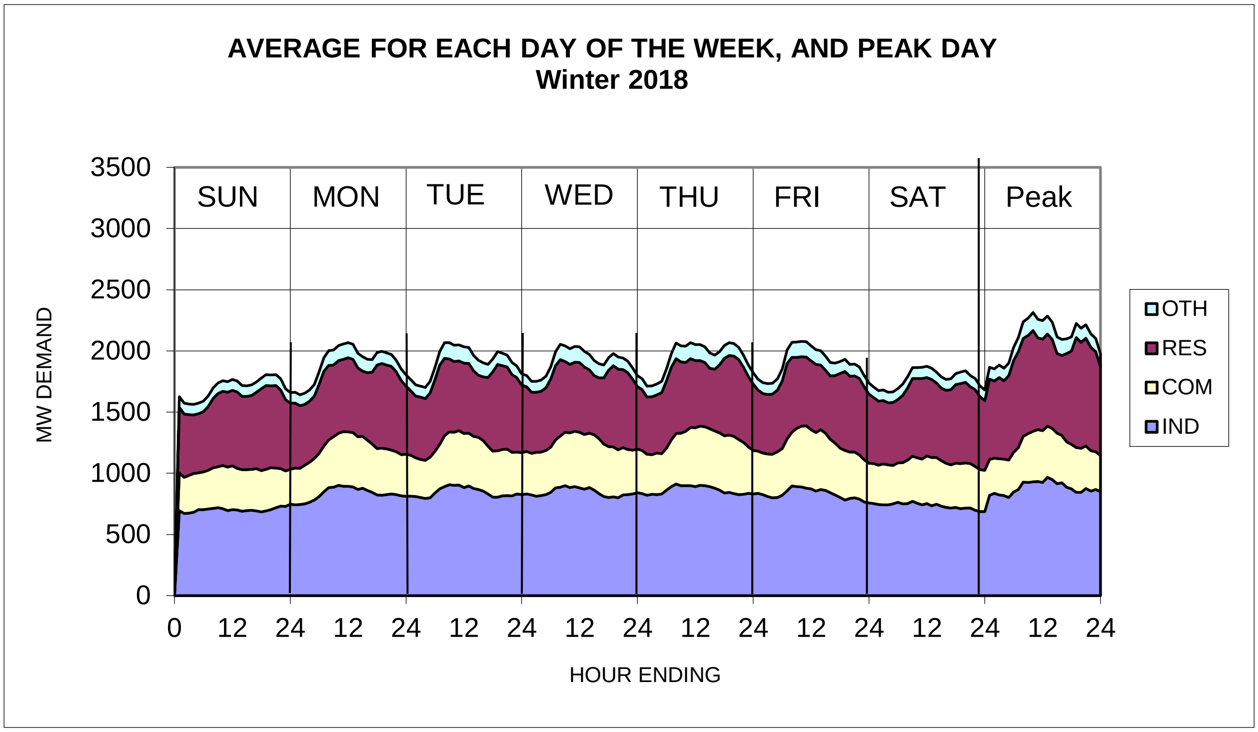
Exhibit A-9

I&M - INDIANA JURISDICTION HOURLY DEMAND BY CLASS



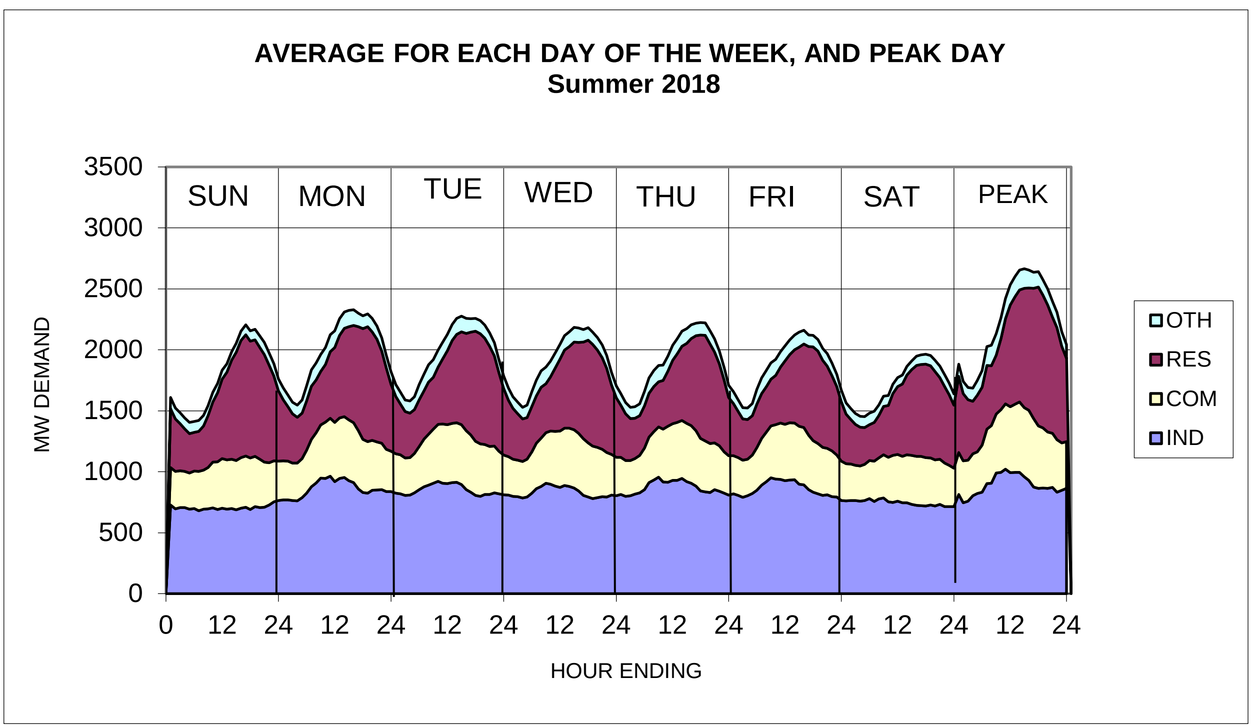


Exhibit A-10

Indiana Michigan Power Company
Recorded and Weather Normalized Peak Load (MW) and Energy (GWh)
2009-2018

		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Indiana Michigan Power Company											
A.	**Peak Load - Summer**										
	1. Recorded	4,262	4,474	4,837	4,726	4,540	4,388	4,398	4,547	4,230	4,369
	2. Weather - Normalized	4,351	4,533	4,479	4,584	4,577	4,519	4,532	4,580	4,512	4,407
B.	**Peak Load - Preceding Winter**										
	1. Recorded	3,728	3,858	3,785	3,686	3,782	3,938	3,952	3,702	3,795	3,723
	2. Weather - Normalized	3,659	3,791	3,808	3,813	3,804	3,825	3,811	3,744	3,704	3,728
C.	**Energy**										
	1. Recorded	24,297	25,829	25,929	25,731	25,719	25,741	25,047	25,407	24,745	25,003
	2. Weather - Normalized	24,630	25,453	25,646	25,651	25,660	25,654	25,100	25,285	25,029	24,576

Exhibit A-11

INDIANA MICHIGAN POWER COMPANY LOAD FORECAST
DATA SOURCES OUTSIDE THE COMPANY

DATA SERIES	FREQUENCY	GEOGRAPHIC	INTERVAL	SOURCE	ADJUSTMENT
Average Daily Temperatures at time of Daily Peak Load	Daily	Selected weather stations throughout the AEP System	1984-2018	NOAA (1) Weather Bank	None
Heating and Cooling Degree-Days	Monthly	Selected weather stations throughout the AEP System	1/84-1/19	NOAA (1) Weather Bank	
Gross Regional Product, Manufacturing	Monthy	U. S.	1984-2054	Moody's Analytics (2)	Extrapolated Forecast
Implicit Deflator-Gross Domestic Product	Monthly	U. S.	1980-2054	Moody's Analytics (2)	Extrapolated Forecast
U.S. Gas Prices, U.S. Gas Consumption	Monthly	U.S.	1980-2054	DOE/EIA (6)	Growth rates used for forecast with historical data, extrapolated forecast
Federal Reserve Board Industrial Production Indexes - Selected Industries	Monthly	U. S.	1975-2054	Moody's Analytics (2) FRB (3)	Annual averages used in long-term models
Residential Appliance Efficiencies, Saturation Trends, Housing Size	Annual, Monthly	East North Central Census Region	1995-2054	DOE via Itron(7) Itron	Extrapolated projections, applied trends to Company Saturations
Commericial Equipment Efficiencies, Saturations Square-Footage	Annual, Monthly	East North Central Census Region	1995-2054	DOE via Itron(8) Itron	Extrapolated projections
U. S., Indiana and Michigan Natural Gas Prices by Sector	Monthly	U. S.	1980-2018	DOE/EIA (4)	None
Gross Regional Product	Monthly	Selected Indiana and Michigan Counties	1980-2054	Moody's Analytics (5)	Extrapolated Forecast
Employment (Total and Selected Sectors), Personal Income and Population	Monthly	Selected Indiana and Michigan Counties	1980-2054	Moody's Analytics (5)	Extrapolated Forecast

Source Citations:
(1) "Local Climatological Data," National Oceanographic and Atmospheric Administration.
(2) December 2018 Forecast, Moody's Analytics
(3) Board of Governors of Federal Reserve System, "Federal Reserve Statistical Release," 1975-2018
(4) U. S. Department of Energy/Energy Information Administration "Natural Gas Monthly," Selected Issues.
(5) December 2018 Regional Forecast, Moody's Analytics
(6) U.S. Department of Energy/Energy Information Administration "Annual Energy Outlook 2019 with Projections to 2050" .
(8) Itron Summer 2018, DOE "Annual Energy Outlook 2018"
(7) Itron Summer 2018 DOE "Annual Energy Outlook 2018"

Exhibit A-12

Indiana Michigan and Indiana and Michigan Jurisdictions
DSM/Energy Efficiency Included in Load Forecast
Energy (GWh) and Coincident Peak Demand (MW)

	I&M DSM/EE			I&M - Indiana DSM/EE			I&M - Michigan DSM/EE		
Year	Energy	Summer* Demand	Winter* Demand	Energy	Summer* Demand	Winter* Demand	Energy	Summer* Demand	Winter* Demand
2019	83.8	18.0	21.8	73.1	16.3	19.9	10.7	1.7	1.9
2020	167.7	37.0	43.8	146.5	33.4	40.0	21.2	3.6	3.9
2021	242.3	53.6	64.6	213.1	48.6	59.0	29.2	5.0	5.6
2022	238.6	50.1	63.5	213.3	46.6	58.5	25.2	3.6	5.0
2023	175.5	30.9	44.1	154.4	29.2	40.5	21.2	1.7	3.6
2024	99.1	12.0	23.4	82.8	11.2	20.9	16.3	0.8	2.5
2025	43.4	3.5	6.7	31.0	2.9	5.1	12.4	0.6	1.6
2026	33.2	1.7	3.5	21.6	1.1	2.3	11.6	0.6	1.2
2027	33.4	1.7	3.6	22.0	1.1	2.3	11.4	0.6	1.2
2028	33.9	1.7	3.6	22.6	1.1	2.4	11.3	0.6	1.2
2029	34.9	1.7	3.7	23.5	1.2	2.5	11.4	0.6	1.2
2030	26.9	1.3	2.9	17.5	0.9	1.9	9.4	0.5	1.0
2031	10.9	0.5	1.2	5.4	0.3	0.6	5.5	0.3	0.6
2032	2.2	0.1	0.2	0.0	0.0	0.0	2.2	0.1	0.2
2033	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2034	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2035	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2036	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2037	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2038	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

***Demand coincident with Company's seasonal peak demand.**

Exhibit A-13

Indiana Michigan Power Company
Short-Term Load Forecast
Blended Forecast vs. Long-Term Model Results

Class	Indiana	Michigan
Residential	Long-Term	Long-Term
Commercial	Long-Term	Long-Term
Industrial	Long-Term	Long-Term
Other Retail	Long-Term	Long-Term

Exhibit A-14

Blending Illustration

Month	Short-term Forecast	Weight	Long-term Forecast	Weight	Blended Forecast
1	1,000	100%	1,150	0%	1,000
2	1,010	100%	1,160	0%	1,010
3	1,020	100%	1,170	0%	1,020
4	1,030	100%	1,180	0%	1,030
5	1,040	83%	1,190	17%	1,065
6	1,050	67%	1,200	33%	1,100
7	1,060	50%	1,210	50%	1,135
8	1,070	33%	1,220	67%	1,170
9	1,080	17%	1,230	83%	1,205
10	1,090	0%	1,240	100%	1,240
11	1,100	0%	1,250	100%	1,250
12	1,110	0%	1,260	100%	1,260

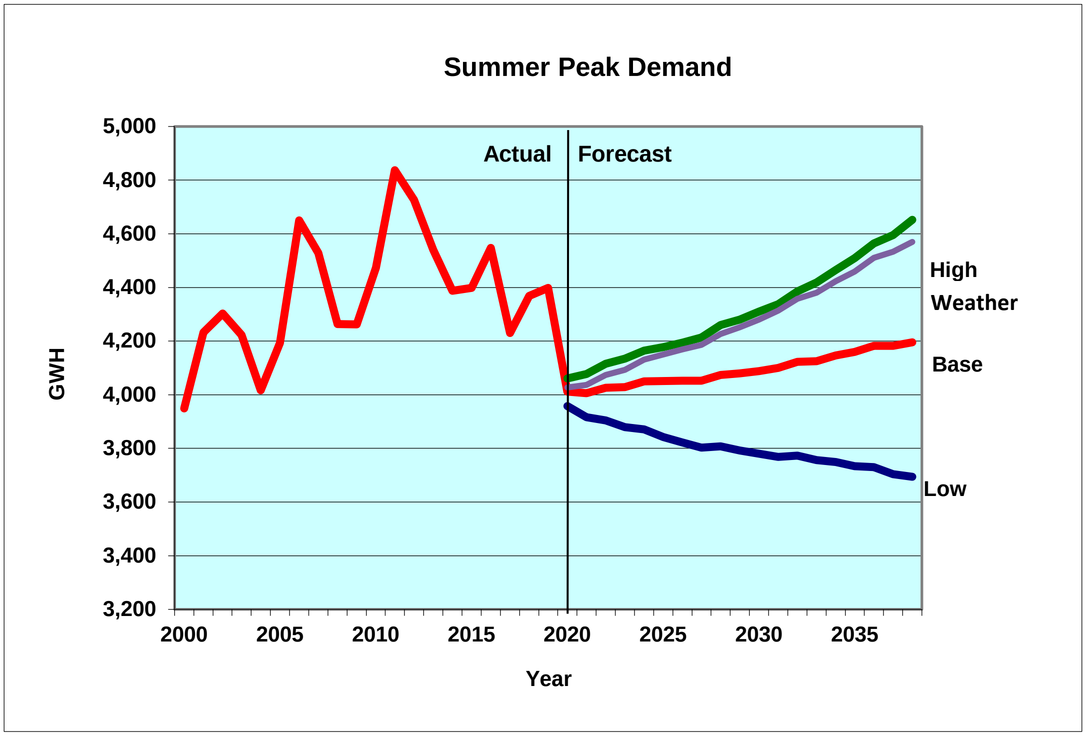
Exhibit A-15

Indiana Michigan Power Company
Low, Base and High Case for
Forecasted Seasonal Peak Demands and Internal Energy Requirements

	Winter Peak Internal Demands (MW)			Summer Peak Internal Demands (MW)			Internal Energy Requirements (GWH)		
Year	**Low Case**	**Base Case**	**High Case**	**Low Case**	**Base Case**	**High Case**	**Low Case**	**Base Case**	**High Case**
2020	3,534	3,582	3,626	3,958	4,012	4,061	22,968	23,281	23,566
2021	3,286	3,362	3,422	3,916	4,006	4,077	22,038	22,544	22,945
2022	3,276	3,378	3,453	3,905	4,026	4,116	21,974	22,657	23,161
2023	3,255	3,381	3,469	3,879	4,029	4,134	21,841	22,686	23,280
2024	3,245	3,395	3,491	3,871	4,050	4,165	21,699	22,700	23,344
2025	3,236	3,412	3,518	3,843	4,051	4,178	21,592	22,765	23,475
2026	3,218	3,413	3,532	3,822	4,053	4,195	21,470	22,768	23,565
2027	3,200	3,410	3,545	3,803	4,052	4,213	21,355	22,754	23,658
2028	3,195	3,418	3,574	3,808	4,074	4,260	21,314	22,802	23,844
2029	3,172	3,412	3,579	3,793	4,080	4,280	21,264	22,874	23,997
2030	3,158	3,415	3,601	3,780	4,088	4,310	21,176	22,902	24,147
2031	3,146	3,423	3,621	3,769	4,100	4,337	21,103	22,957	24,287
2032	3,139	3,430	3,648	3,773	4,122	4,385	21,066	23,017	24,484
2033	3,130	3,437	3,681	3,757	4,126	4,418	21,018	23,082	24,718
2034	3,104	3,433	3,697	3,749	4,147	4,465	20,934	23,152	24,928
2035	3,089	3,442	3,731	3,734	4,160	4,509	20,841	23,218	25,166
2036	3,076	3,450	3,764	3,730	4,183	4,564	20,750	23,270	25,393
2037	3,060	3,455	3,796	3,704	4,183	4,595	20,650	23,318	25,618
2038	3,049	3,463	3,840	3,694	4,196	4,652	20,583	23,377	25,920
2039	3,042	3,471	3,887	3,688	4,209	4,713	20,542	23,442	26,247
Average Annual Growth Rate % - 2020-2039									
	-0.8	-0.2	0.4	-0.4	0.3	0.8	-0.6	0.0	0.6

Exhibit A-16

Indiana Michigan Power Company
Range of Forecasts and Weather Scenario



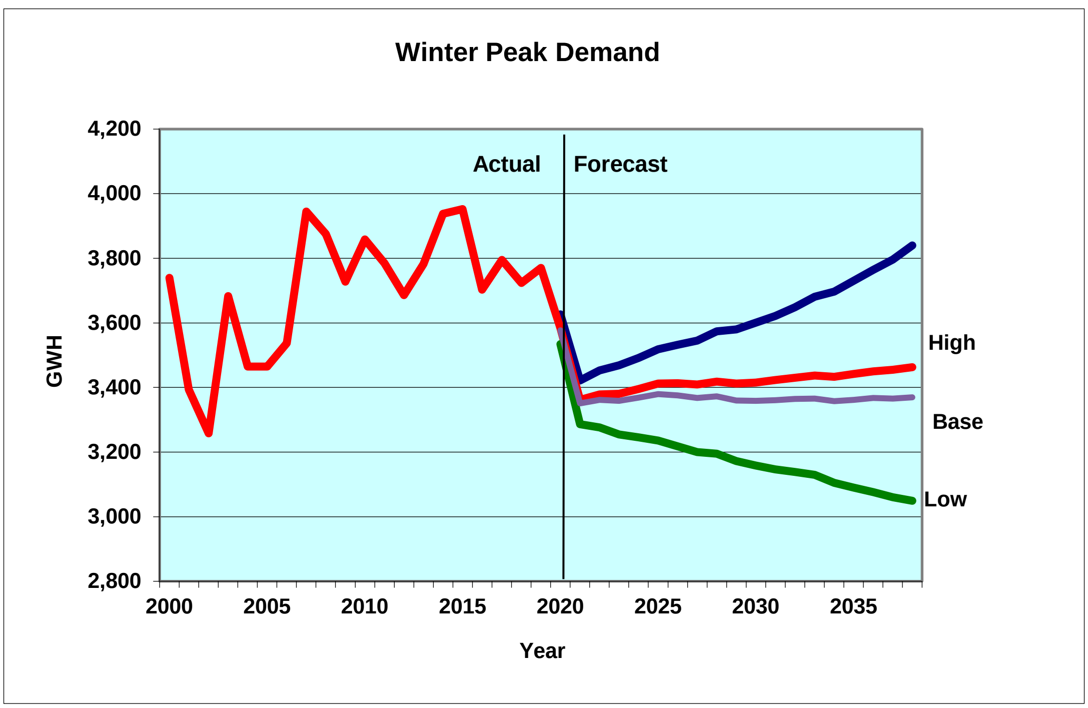


Exhibit A-17

Indiana Michigan Power Company
Forecasted DSM, Adjusted for IRP Modeling

Year	Energy (MWh)	Summer Peak (MW)	Winter Peak (MW)
2019	83,786	18.0	21.8
2020	167,689	37.0	43.8
2021	27,452	5.0	-
2022	-	-	-
2023	-	-	-
2024	-	-	-
2025	-	-	-
2026	-	-	-
2027	-	-	-
2028	-	-	-
2029	-	-	-
2030	-	-	-
2031	-	-	-
2032	-	-	-
2033	-	-	-
2034	-	-	-
2035	-	-	-
2036	-	-	-
2037	-	-	-
2038	-	-	-

Exhibit B IRP Public Summary Document

INTEGRATED RESOURCE PLANNING
PUBLIC SUMMARY




INDIANA MICHIGAN POWER
An AEP Company
BOUNDLESS ENERGY

I&M 2018-19 IRP Public Summary

Indiana Michigan Power Company (I&M or Company) customers consist of both retail and sales-for-resale (wholesale) customers located in the states of Indiana, and Michigan (see Figure 1). Currently, I&M serves approximately 466,000 and 129,000 retail customers in the states of Indiana and 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 4,837MW, which occurred in July 2011; and the highest recorded winter peak was 3,952MW, which occurred in January 2015. The most recent (summer 2018 and winter 2018/19) actual I&M summer and winter peak demands were 4,369MW and 3,770MW, occurring on June 18, 2018 and January 30, 2019, respectively.

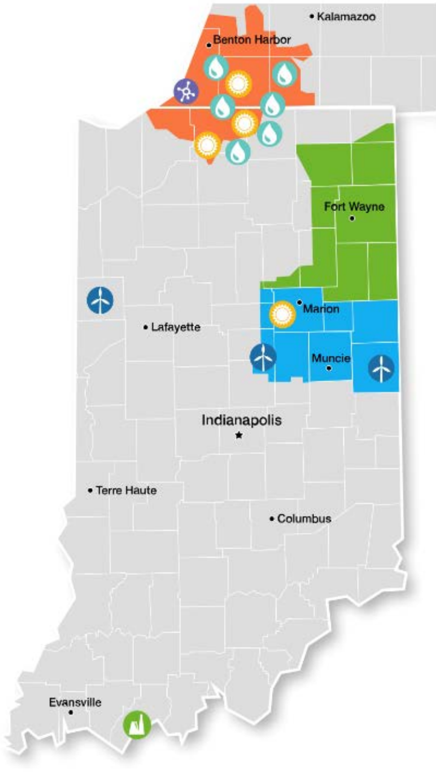


Figure 1. I&M Service Territory

Over the next 20 year period (2019-2038) I&M's service territory is expected to see population and non-farm employment growth of 0.0% and 0.3% 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 0.1% per year with stronger growth expected from the industrial class (+0.4% per year) while the residential class remains relatively flat and the commercial class experiences a decline (-0.3% per year) over the forecast horizon. Finally, I&M's internal energy and peak demand are expected to decrease at an average rate of 0.2% and 0.2% per year, respectively, through 2038.

Indiana IRP Stakeholder Process

I&M implemented an enhanced stakeholder outreach/public advisory process to guide the development of its Integrated Resource Plan. I&M designed and implemented the IRP public advisory process in accordance with the requirements of Commission Rule 170 IAC 4-7-2.6. I&M's goal throughout the process was to improve its resource planning process by conducting a meaningful, transparent and comprehensive stakeholder outreach effort to explore a wide-range of assumptions and resource options as I&M anticipates substantial changes in its resource mix over the IRP planning period. The result of this process is a well-reasoned, vetted Preferred Plan, based on current assumptions, to help guide I&M's future resource decisions. Some key take-aways from the process are summarized below:

- Evaluating a "High Renewables" scenario;
- Evaluating Rockport scenarios with and without carbon futures;
- Evaluating an "EE Decrement" approach;
- Modifying EE potential to reflect the Market Potential Study;
- Evaluating unconstrained renewable build scenarios;
- Evaluating portfolios with Low Load with Low Band pricing and the High Load with High Band pricing;
- Providing access to the Company's modeling software and associated training; and
- Providing opportunities at all Stakeholder meetings for stakeholders to present and discuss key issues, including a presentation by students from Ball State University Immersive Learning Project.

Planning Process

The objective of a resource planning effort is to recommend a system resource plan that balances least-cost objectives with planning flexibility, asset mix considerations, adaptability to risk, conformance with applicable North American Electric Reliability Corporation (NERC) and RTO criteria. In addition, given the unique impact of fossil-fired generation on the environment, the planning effort must ultimately be in concert with anticipated long-term requirements as established by the EPA-driven environmental compliance planning process.

The information presented with the IRP includes descriptions of assumptions, study parameters, methodologies, and results, including the integration of traditional supply-side resources, renewable energy resources, distributed generation and DSM programs.

In general, assumptions and plans are reviewed and modified periodically when new information becomes available. On-going analysis is required by multiple disciplines across I&M and AEP to ensure that market structures and governances, technical parameters, regulatory constructs, capacity supply, energy adequacy and operational reliability, and environmental mandate requirements are current to ensure optimal capacity resource planning.

Further influencing this process are a growing number of federal and state initiatives that address many issues relating to industry restructuring, customer choice, and reliability planning. Currently, fulfilling a regulatory obligation to serve native load customers represents one of the cornerstones of the I&M IRP process. Therefore, as a result, the “objective function” of the modeling applications utilized in this process is the establishment of the least-cost plan, with *cost* being more accurately described as *revenue requirement* under a traditional ratemaking construct.

That does not mean, however, that the most appropriate plan is the one with the absolute least cost over the planning horizon evaluated. Other factors were considered in the determination of the Plan. To challenge the robustness of the IRP, sensitivity analyses were performed to address these factors.

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.

Summary of I&M's Resource Plan

I&M has analyzed various scenarios that would provide adequate supply and demand resources to meet its projected peak load obligations, and reduce or minimize costs to its customers, including energy costs, for the next twenty years. Following are the key components and inputs of I&M's Preferred Plan:

- Continue operation of the Cook units through the remainder of their current license periods;
- The Rockport Unit 2 lease expires at the end of 2022 and retire Rockport Unit 1 at the end of 2028;
- Continue deployment of supply-side renewable resource including the addition of over 3600 MW of wind and large scale solar by 2038, beginning in 2022;
- Incorporate 50MW of Batteries and 54MW of Micro/Mini-Grid resources by 2028;
- Add 2,700MW of Natural Gas Combined Cycle (NGCC) generation including 770 MW in 2028 to replace Rockport capacity, 770MW in 2034 to replace Cook Unit 1 and 1,155MW in 2037 to replace Cook Unit 2 at the end of their current license periods;
- Incorporates demand-side resources including 180MW of Energy Efficiency (EE) and Demand Response (DR) and
- Recognizes that residential and commercial customers will add distributed resources, primarily in the form of residential and commercial rooftop solar (i.e. Distributed Generation [DG]).

Figure 2 below shows I&M's "going-in" capacity position (i.e. before resource additions) over the planning period, which uses the PJM summer peak to determine resource requirements. 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 not renewing its lease of Rockport Unit 2. This capacity shortfall is anticipated to increase to 1,762MW in 2028 upon the retirement of Rockport Unit 1. The retirement of Cook Unit 1 in 2034 and Cook Unit 2 in 2038 further exposes I&M's capacity shortfall to 4,060MW.

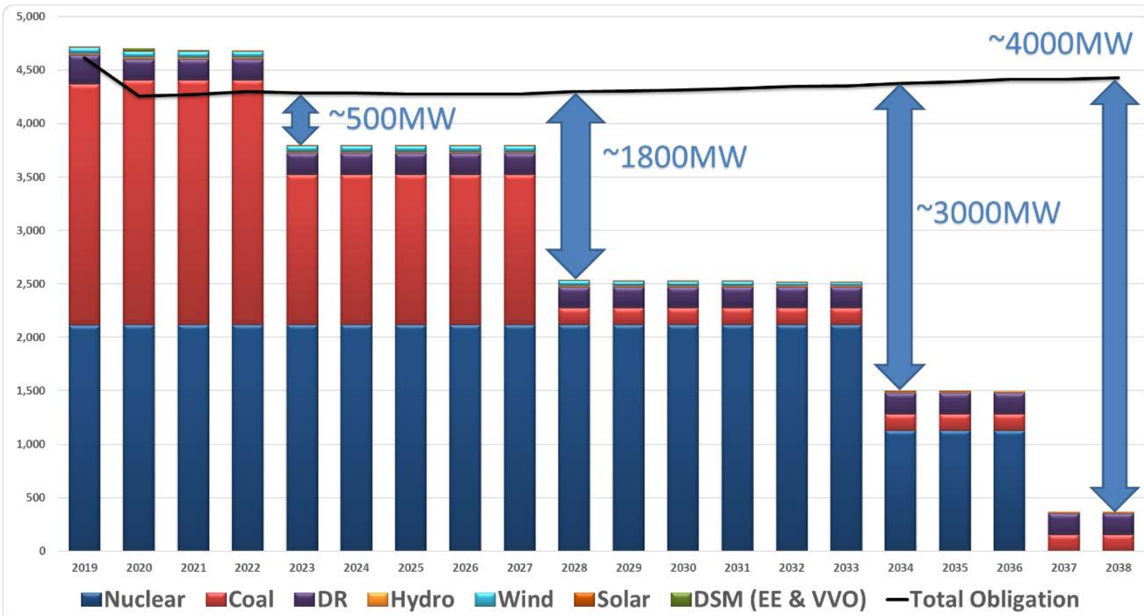


Figure 2. I&M "Going-In" Position

I&M has identified a diverse set of resources to address the capacity deficit position over the planning period. (Figure 3) These additions, which include solar, wind, natural gas, energy storage and energy efficiency resources along with short-term market purchases (STMP), are expected to eliminate the capacity deficit through the planning period. The solar resources are assumed to provide PJM capacity equal to 51.1% of their nameplate rating (or 102MW for 200MW of nameplate solar) and wind resources are assumed to provide PJM capacity equal to 12.3% of their nameplate rating (or 37MW for 300 MW of nameplate wind).

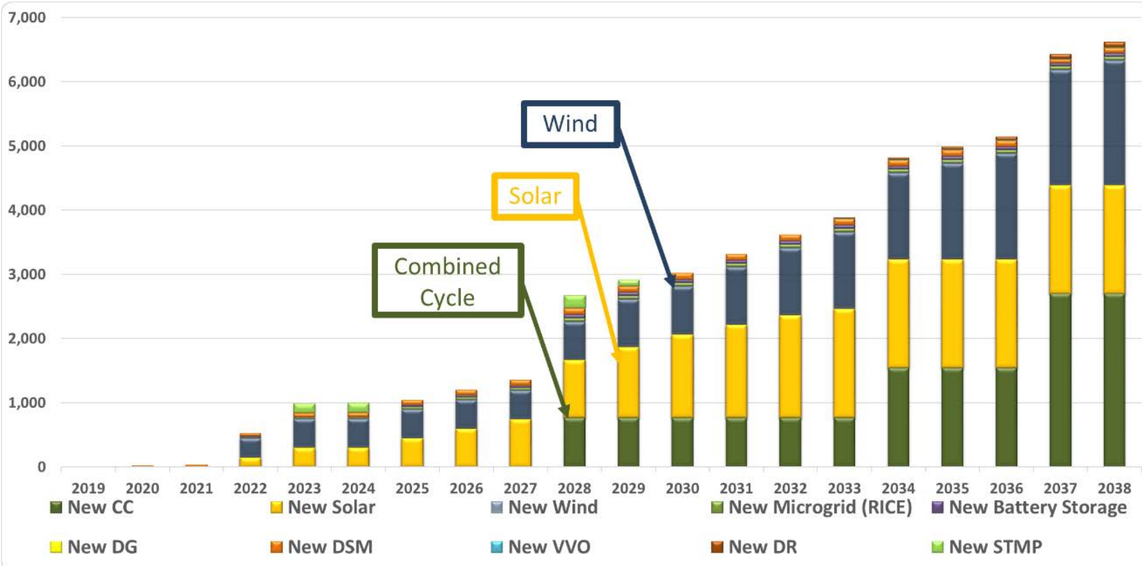


Figure 3. I&M New Capacity Additions – Nameplate (MW)

The resource additions allow I&M to satisfy its PJM load obligations over the planning period. Additionally, EECO and customer owned generation such as rooftop solar will also improve I&M's capacity position.

Figure 4 illustrates I&M's commitment to renewables and DSM over the planning period. The first nine years of the plan focuses on adding smaller, geographically diverse resources consisting of solar, wind, DSM, energy storage, microgrids and short-term market purchases. The quantity of these potential resource additions depends on the specific resources available (and their cost) during a "resources acquisition" process, providing the Company flexibility to acquire more or less of these planned resources at those times. This flexibility included in the Preferred Plan may ultimately lead to a delay or the elimination of one or more of the combined cycle resources added over the planning period.

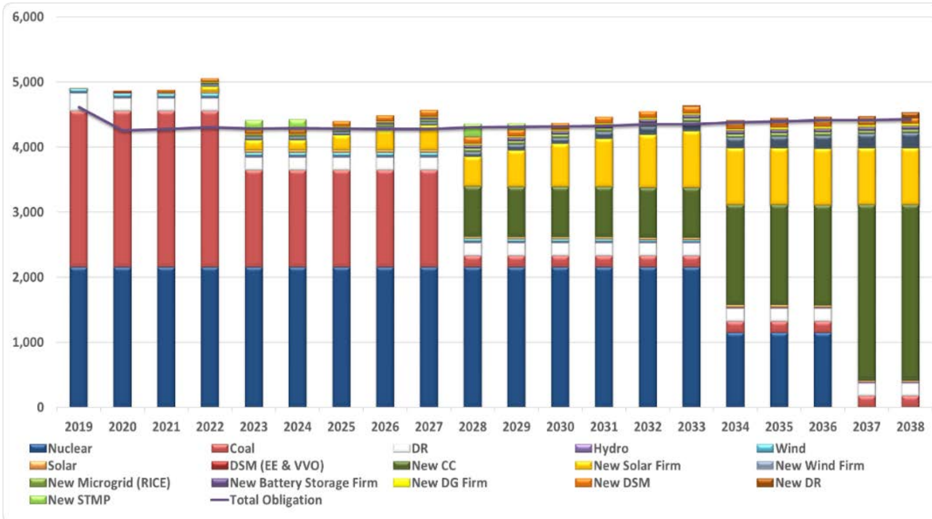


Figure 4. Existing and New Capacity Additions – FIRM (MW)

The capacity contribution from renewable resources is modest due to their intermittent characteristic; however, those resources (particularly wind) provide a significant volume of energy. Figure 5 and Figure 6 show annual changes in energy mix that result from the Preferred Plan over the planning period. I&M's energy output shows a significant transformation away from coal and nuclear while the energy output attributable to renewable generation (wind and solar) grows.

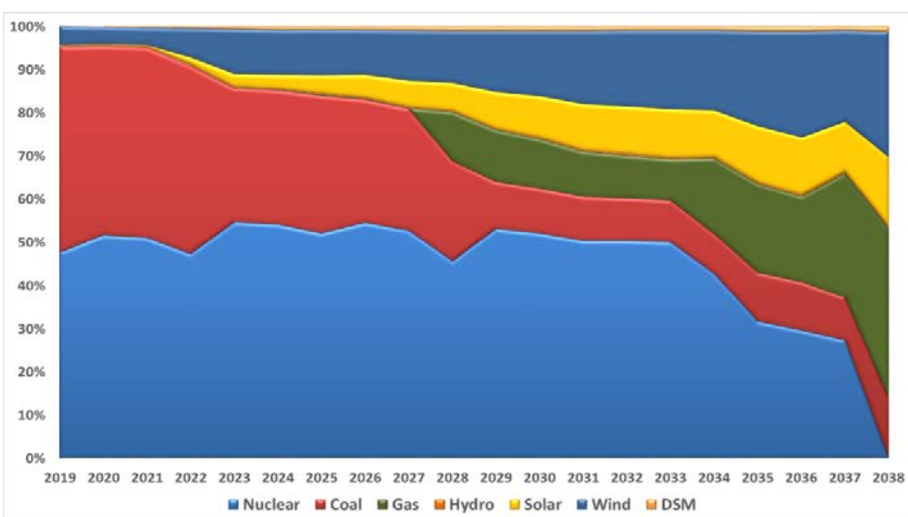


Figure 5. I&M's Preferred Plan Percentage of Annual Energy by Supply Type (%)

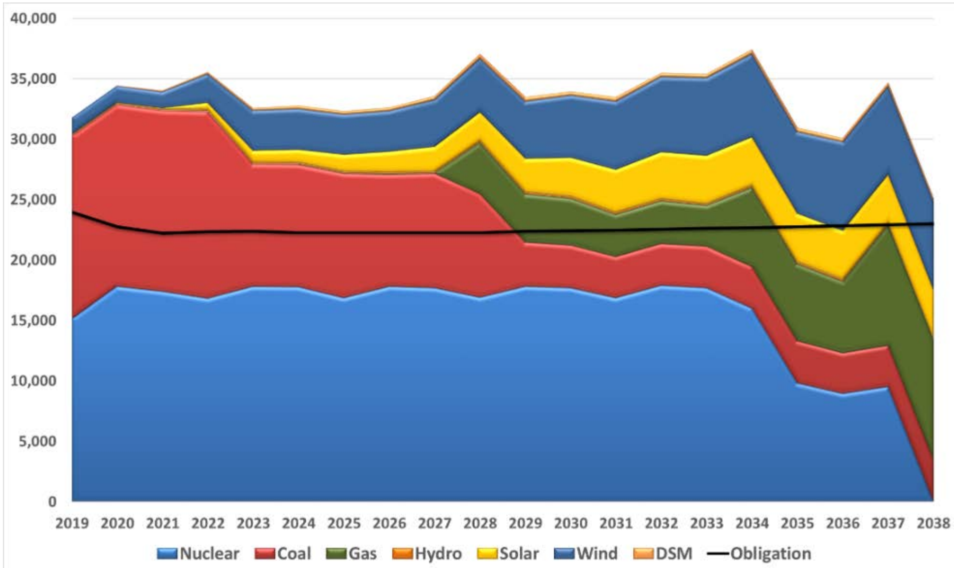


Figure 6. I&M's Preferred Plan Annual Energy Position (GWh)

Figure 7 provides insight to the emissions reductions over the planning period for the Preferred Plan. The Preferred Plan results in reductions from 2019 levels (baseline) of 65% for CO_2, and over 90% for NOx and SO_2 emissions by 2038.

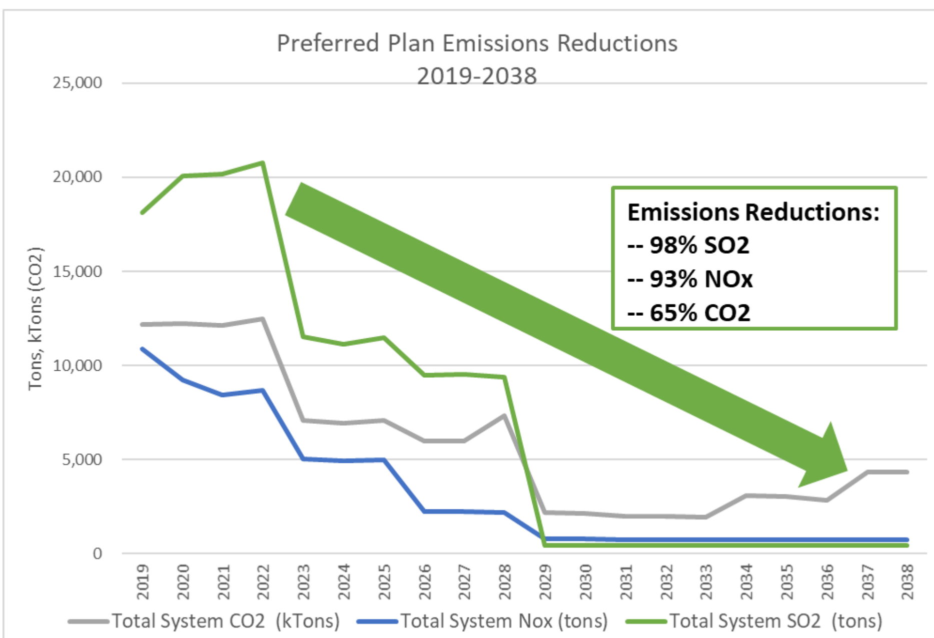


Figure 7. Preferred Plan Emissions Reductions

Conclusion

The resource portfolios developed for this IRP reflect, largely, assumptions that are subject to change; as an IRP is simply a snapshot of the future at a given time. As noted previously, this IRP is not a commitment to specific resource additions or other courses of action. The resource planning process continues to be complex, especially with regard to such things as technology advancement, changing energy supply pricing fundamentals, uncertainty of demand, and end-use efficiency improvements. These complexities exacerbate the need for flexibility and adaptability in any ongoing planning activity and resource planning process.

With this in mind, the Preferred Plan provides reliable utility service over the 20-year planning period at reasonable cost, through a combination of renewable supply-side resources and demand-side programs in the near term and renewable and gas-fired resources in the long-term. The plan provides a roadmap for I&M to serve its customers' peak load and energy requirements throughout the 20-year planning period. The Preferred Plan includes incremental resources that will provide—in addition to the needed capacity to achieve mandatory PJM peak demand requirements—additional carbon-free energy to reduce the long-term exposure of the Company's customers to PJM energy markets and potential carbon emission restrictions.

Exhibit C Case and Scenario Results

Indiana & Michigan POWER COMPANY
INTEGRATED RESOURCE PLAN

RP1 retires (12/31/2028) & RP2 no lease extension (12/31/2022) CASE 9 (Case 5 & Preferred Plan) Base Band Pricing

	Utility Costs (Nominal$000)								
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(1)thru(7)-(8)
	Load Cost	Fuel Costs	Emission Costs	Existing System FOM + OGC	(Incremental) Fixed + Variable + Lease Costs +ST PPA	(Incremental) Capital + Renewable + VVO Program Costs	Contract (Revenue)/Cost	*Less:* Market Revenue	GRAND TOTAL, Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000
2019	678,067	364,680	24,194	29,683	193,358	0	43,387	757,369	576,000
2020	653,672	368,811	24,193	35,392	205,101	8,072	44,403	845,203	494,442
2021	642,024	363,181	23,997	40,613	205,444	8,139	44,832	840,334	487,897
2022	670,720	372,595	24,605	50,293	213,602	66,264	39,336	906,869	530,546
2023	697,906	245,732	13,638	37,520	95,536	101,929	36,163	818,568	409,856
2024	727,080	248,361	13,667	49,700	98,801	101,420	34,582	855,927	417,684
2025	750,837	254,078	14,024	41,771	96,415	125,638	34,187	869,502	447,447
2026	773,155	235,862	13,766	44,934	104,447	141,018	30,309	916,058	427,434
2027	802,988	247,057	13,909	45,395	109,825	155,872	28,066	963,293	439,820
2028	1,004,061	373,840	103,542	50,938	135,545	290,650	16,580	1,401,776	573,381
2029	1,011,147	231,247	20,735	38,228	137,854	338,355	9,317	1,244,800	542,083
2030	1,033,175	235,585	20,894	38,228	143,077	356,432	(1,209)	1,283,681	542,502
2031	1,050,471	222,222	19,433	38,228	145,353	400,589	(646)	1,289,787	585,863
2032	1,081,557	234,586	20,376	38,228	157,675	445,887	(1,580)	1,416,523	560,205
2033	1,105,223	233,894	20,082	38,228	164,669	498,357	(9,269)	1,464,668	586,517
2034	1,136,325	340,117	39,954	38,228	179,170	624,004	(11,588)	1,616,382	729,828
2035	1,181,663	300,879	40,593	38,228	150,670	654,203	(23,437)	1,376,071	966,728
2036	1,190,603	285,452	39,275	38,228	150,377	684,779	(22,419)	1,348,590	1,017,705
2037	1,226,123	456,997	67,893	38,228	185,243	869,891	(22,757)	1,681,375	1,140,243
2038	1,270,871	397,992	69,505	38,228	139,617	901,404	(26,502)	1,239,139	1,551,977
2039	1,305,270	408,591	71,442	33,438	144,662	933,207	(30,398)	1,292,874	1,573,338
2040	1,330,720	401,166	70,780	29,682	153,864	940,872	(42,150)	1,297,146	1,587,788
2041	1,350,531	359,829	62,879	23,561	153,417	944,178	(45,208)	1,232,040	1,617,147
2042	1,388,191	359,395	62,427	14,524	158,390	939,761	(46,325)	1,249,042	1,627,322
2043	1,411,141	325,270	56,546	12,155	161,873	940,492	(46,938)	1,210,492	1,650,046
2044	1,466,439	341,722	58,778	9,631	168,832	940,933	(48,687)	1,260,151	1,677,497
2045	1,495,103	292,693	50,128	7,674	171,989	944,134	(49,443)	1,204,766	1,707,512
2046	1,541,599	285,677	48,820	5,623	173,667	944,931	(48,358)	1,213,693	1,738,264
2047	1,584,176	275,509	47,384	3,136	179,831	940,460	(41,520)	1,225,405	1,763,573
2048	1,606,514	280,862	48,459	0	190,926	904,940	(42,624)	1,241,666	1,747,412

Indiana & Michigan POWER COMPANY
INTEGRATED RESOURCE PLAN
RP1 retires (12/31/2028) & RP2 no lease extension (12/31/2022) CASE 9 (Case 5 & Preferred Plan) Base Band Pricing

	Resource (Capacity) Additions									
	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
	(Current and Planned) Supply-Side + Purchased Unforced Capacity (UCAP)		(Increm) EE+ VVO + DR + Battery		Distributed Solar		Generic Wind		Utility Solar	
	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW
2019	4,417	4,417	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2020	46	4,463	18.6	18.6	0.0	0.0	0.0	0.0	0.0	0.0
2021	11	4,474	17.4	36.1	0.0	0.0	0.0	0.0	0.0	0.0
2022	29	4,503	24.0	60.0	10.4	10.4	36.9	36.9	76.3	76.3
2023	(699)	3,804	11.6	71.6	2.1	12.4	18.5	55.4	76.3	152.6
2024	0	3,804	9.0	80.6	2.5	14.9	0.0	55.4	0.0	152.6
2025	(132)	3,672	29.9	110.5	0.8	15.7	0.0	55.4	76.3	228.9
2026	0	3,672	8.9	119.4	0.8	16.6	0.0	55.4	76.3	305.1
2027	0	3,672	7.4	126.8	0.8	17.4	0.0	55.4	76.3	381.4
2028	(273)	3,399	28.1	154.9	1.2	18.6	18.5	73.8	76.3	457.7
2029	(107)	3,292	(8.4)	146.5	1.7	20.3	18.5	92.3	101.7	559.4
2030	(100)	3,192	5.8	152.2	1.7	21.9	0.0	92.3	101.7	661.1
2031	0	3,192	(1.2)	151.0	1.7	23.6	18.5	110.7	76.3	737.4
2032	(13)	3,179	0.4	151.4	1.7	25.3	18.5	129.2	76.3	813.7
2033	0	3,179	23.1	174.5	2.5	27.7	18.5	147.6	50.9	864.5
2034	(247)	2,932	12.8	187.3	2.1	29.8	18.5	166.1	0.0	864.5
2035	0	2,932	16.8	204.1	1.7	31.5	18.5	184.5	0.0	864.5
2036	(7)	2,925	9.3	213.3	1.7	33.1	18.5	203.0	0.0	864.5
2037	28	2,953	(22.0)	191.4	1.7	34.8	18.5	221.4	0.0	864.5
2038	0	2,953	40.0	231.3	1.7	36.4	18.5	239.9	0.0	864.5
2039	0	2,953	7.9	239.3	2.1	38.5	18.5	258.3	0.0	864.5
2040	(56)	2,897	4.1	243.4	1.7	40.2	0.0	258.3	0.0	864.5
2041	(50)	2,847	20.5	263.9	2.1	42.2	0.0	258.3	0.0	864.5
2042	0	2,847	12.3	276.1	2.1	44.3	0.0	258.3	0.0	864.5
2043	0	2,847	20.0	296.1	2.1	46.4	0.0	258.3	0.0	864.5
2044	0	2,847	20.7	316.8	2.5	48.9	0.0	258.3	0.0	864.5
2045	0	2,847	30.4	347.2	2.5	51.3	0.0	258.3	0.0	864.5
2046	(50)	2,797	19.9	367.1	2.5	53.8	0.0	258.3	0.0	864.5
2047	0	2,797	13.3	380.4	2.9	56.7	0.0	258.3	0.0	864.5
2048	50	2,847	(45.3)	335.2	2.9	59.6	0.0	258.3	0.0	864.5

	Energy & Capacity Positions												Carbon Output		NOX Output	SOX Output	
	(20)	(21)	(22)	(23)=(20)+(21)+(22)	(24)	(25)	(26)=(24)-(25)	(27)=(23)-(26)	(28)	(29)	(30)=(28)-(29)	(31)	(32)	(33)			
	Thermal Generation + Hydro	(Current) Purchased Energy Including OVEC	(New) Generic Wind + Utility Solar	= Market Sales	Load (Net of Embedded EE)	*Less:* (Increm) Energy Efficiency+ VVO+Dist Solar	= Net Load Requirements	ENERGY Surplus	Capacity	Peak + Reserves	CAPACITY Surplus	Reserve Margin	Existing Units CO2 Emissions	Total System CO2	Total System Nox	Total System SO2	
	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	%	tons	tons	tons	tons	
2019	26,221	2,712	0	28,932	23,943	0	23,943	4,989	4,417	4,339	78	10.8	12,188,418	12,188,418	10,882	18,127	2019
2020	28,937	2,669	0	31,606	22,817	76	22,741	8,865	4,482	4,059	423	20.2	12,244,217	12,244,217	9,229	20,051	2020
2021	28,427	2,689	0	31,116	22,233	146	22,086	9,029	4,510	4,078	432	20.4	12,121,702	12,121,702	8,435	20,162	2021
2022	28,147	2,881	1,314	32,342	22,367	244	22,123	10,219	4,687	4,104	583	24.3	12,486,557	12,498,609	8,660	20,773	2022
2023	23,684	2,943	2,168	28,796	22,332	298	22,034	6,762	4,096	4,088	8	9.1	7,084,506	7,096,143	5,040	11,522	2023
2024	23,571	2,963	2,178	28,712	22,270	342	21,928	6,784	4,107	4,090	18	9.3	6,919,992	6,932,017	4,920	11,149	2024
2025	22,784	2,967	2,491	28,241	22,277	387	21,890	6,351	4,082	4,082	0	8.9	7,048,181	7,070,394	4,995	11,481	2025
2026	22,732	2,961	2,813	28,505	22,270	428	21,842	6,664	4,168	4,082	86	11.2	5,952,319	5,973,309	2,233	9,490	2026
2027	22,648	2,980	3,135	28,763	22,257	463	21,794	6,969	4,253	4,081	172	13.4	5,964,764	5,986,086	2,234	9,513	2027
2028	26,078	2,829	4,004	32,911	22,304	501	21,804	11,107	4,104	4,104	0	8.9	5,754,443	7,313,561	2,171	9,371	2028
2029	21,948	2,589	4,951	29,487	22,375	472	21,903	7,584	4,110	4,110	0	8.9	725,348	2,197,542	798	467	2029
2030	21,724	2,415	5,380	29,518	22,395	501	21,894	7,625	4,120	4,119	1	8.9	705,266	2,138,608	787	453	2030
2031	20,491	2,394	6,234	29,119	22,432	501	21,931	7,188	4,215	4,130	84	11.1	681,402	1,969,410	761	438	2031
2032	21,560	2,412	7,116	31,087	22,482	506	21,976	9,111	4,299	4,154	145	12.7	695,758	2,000,592	768	447	2032
2033	21,204	2,090	7,835	31,128	22,543	551	21,993	9,136	4,393	4,157	236	15.1	686,265	1,928,793	738	441	2033
2034	22,658	2,048	8,368	33,074	22,612	551	22,061	11,013	4,180	4,179	1	8.9	691,106	3,079,587	754	444	2034
2035	16,361	1,408	8,900	26,669	22,676	559	22,117	4,551	4,217	4,193	23	9.5	700,076	3,044,723	754	448	2035
2036	15,046	1,378	9,471	25,895	22,727	540	22,187	3,708	4,239	4,217	22	9.4	674,905	2,866,701	740	434	2036
2037	19,660	1,374	9,964	30,998	22,774	518	22,257	8,742	4,265	4,217	48	10.1	687,037	4,347,780	742	441	2037
2038	10,042	1,382	10,496	21,920	22,831	507	22,324	(404)	4,325	4,231	94	11.3	695,223	4,316,174	757	446	2038
2039	9,974	1,382	11,028	22,384	22,895	490	22,405	(21)	4,354	4,245	108	11.6	693,847	4,289,841	750	445	2039
2040	9,553	1,150	11,081	21,783	22,945	462	22,483	(700)	4,303	4,276	28	9.6	436,977	3,879,183	517	281	2040
2041	8,215	754	11,028	19,997	22,987	498	22,489	(2,492)	4,276	4,276	0	8.9	0	2,954,548	0	0	2041
2042	7,885	754	11,028	19,668	23,030	503	22,528	(2,860)	4,290	4,288	3	8.9	0	2,834,097	0	0	2042
2043	6,917	755	11,028	18,700	23,079	536	22,544	(3,844)	4,312	4,299	13	9.2	0	2,480,314	0	0	2043
2044	6,947	756	11,080	18,783	23,125	573	22,552	(3,769)	4,335	4,322	13	9.2	0	2,491,003	0	0	2044
2045	5,744	756	11,028	17,529	23,177	645	22,532	(5,003)	4,368	4,329	40	9.9	0	2,052,576	0	0	2045
2046	5,411	720	11,028	17,159	23,238	675	22,563	(5,403)	4,341	4,341	0	8.9	0	1,931,418	0	0	2046
2047	5,081	605	11,028	16,715	23,296	681	22,615	(5,900)	4,357	4,353	4	9.0	0	1,811,240	0	0	2047
2048	5,023	607	11,078	16,707	23,081	558	22,523	(5,816)	4,365	4,365	0	8.9	0	1,789,669	0	0	2048

Indiana & Michigan POWER COMPANY
INTEGRATED RESOURCE PLAN

RP1 retires (12/31/2028) & RP2 no lease extension (12/31/2022) CASE 1 Base Band Commodity Pricing

	Utility Costs (Nominal$000)								
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(1)thru(7)-(8)
	Load Cost	Fuel Costs	Emission Costs	Existing System FOM + OGC	(Incremental) Fixed + Variable + Lease Costs +ST PPA	(Incremental) Capital + Renewable + VVO Program Costs	Contract (Revenue)/Cost	*Less:* Market Revenue	GRAND TOTAL, Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000
2019	678,067	364,680	24,194	29,683	193,358	0	43,387	757,369	576,000
2020	653,672	368,811	24,193	35,392	205,101	8,072	44,403	845,203	494,442
2021	642,024	363,181	23,997	40,613	205,444	8,139	44,832	840,334	487,897
2022	670,720	371,873	24,605	50,293	213,172	61,697	39,336	905,683	526,013
2023	697,906	244,995	13,638	37,520	95,931	101,830	36,163	820,947	407,036
2024	727,080	247,568	13,667	49,700	98,936	118,525	34,582	870,830	419,228
2025	750,837	252,534	14,024	41,771	98,987	134,014	34,187	881,922	444,433
2026	773,155	234,339	13,766	44,934	107,091	149,394	30,309	928,914	424,075
2027	802,988	245,447	13,909	45,395	112,506	192,058	28,066	995,306	445,065
2028	1,004,061	370,928	103,049	50,938	138,570	344,270	16,580	1,454,319	574,078
2029	1,011,147	228,567	20,274	38,228	140,547	389,421	9,317	1,294,327	543,175
2030	1,033,175	232,937	20,438	38,228	147,707	401,178	(1,209)	1,328,659	543,797
2031	1,050,471	219,816	19,022	38,228	151,044	447,287	(646)	1,337,379	587,843
2032	1,081,557	232,035	19,931	38,228	161,419	479,621	(1,580)	1,450,335	560,876
2033	1,105,223	231,329	19,633	38,228	166,478	511,999	(9,269)	1,486,811	576,810
2034	1,136,325	337,634	39,520	38,228	181,048	638,103	(11,588)	1,639,833	719,437
2035	1,181,663	298,250	40,132	38,228	152,579	670,286	(23,437)	1,400,464	957,236
2036	1,190,603	282,953	38,829	38,228	152,363	699,397	(22,419)	1,373,598	1,006,357
2037	1,226,123	454,480	67,447	38,228	187,280	883,534	(22,757)	1,707,107	1,127,228
2038	1,270,871	395,326	69,030	38,228	141,690	915,046	(26,502)	1,265,401	1,538,287
2039	1,305,270	405,980	70,976	33,438	146,804	915,324	(30,398)	1,290,836	1,556,556
2040	1,330,720	398,565	70,309	29,682	156,070	926,697	(42,150)	1,295,373	1,574,521
2041	1,350,531	357,601	62,479	23,561	156,317	949,815	(45,208)	1,234,882	1,620,215
2042	1,388,191	357,271	62,048	14,524	161,385	932,252	(46,325)	1,251,888	1,617,458
2043	1,411,141	323,429	56,218	12,155	164,426	947,763	(46,938)	1,214,556	1,653,637
2044	1,466,439	339,843	58,446	9,631	170,885	950,243	(48,687)	1,266,709	1,680,091
2045	1,495,103	291,066	49,843	7,674	173,546	938,991	(49,443)	1,208,658	1,698,123
2046	1,541,599	284,080	48,541	5,623	183,019	925,862	(48,358)	1,213,377	1,726,988
2047	1,584,176	273,931	47,107	3,136	188,534	921,967	(41,520)	1,222,129	1,755,202
2048	1,606,514	279,251	48,175	0	200,626	894,066	(42,624)	1,238,713	1,747,294

Indiana & Michigan POWER COMPANY
INTEGRATED RESOURCE PLAN
RP1 retires (12/31/2028) & RP2 no lease extension (12/31/2022) CASE 1 Base Band Commodity Pricing

	Resource (Capacity) Additions										Energy & Capacity Positions												Carbon Output		NOX Output	SOX Output	
	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)=(20)+(21)+(22)	(24)	(25)	(26)=(24)-(25)	(27)=(23)-(26)	(28)	(29)	(30)=(28)-(29)	(31)	(32)	(33)			
	(Current and Planned) Supply-Side + Purchased Unforced Capacity (UCAP)		(Increm) EE+ VVO + DR + Battery		Distributed Solar		Generic Wind		Utility Solar		Thermal Generation + Hydro	(Current) Purchased Energy Including OVEC	(New) Generic Wind + Utility Solar	= Market Sales	Load (Net of Embedded EE)	*Less:* (Increm) Energy Efficiency+ VVO+Dist Solar	= Net Load Requirements	ENERGY Surplus	Capacity	Peak + Reserves	CAPACITY Surplus	Reserve Margin	Existing Units CO2 Emissions	Total System CO2	Total System Nox	Total System SO2	
	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	%	tons	tons	tons	tons	
2019	4,417	4,417	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	26,221	2,712	0	28,932	23,943	0	23,943	4,989	4,417	4,339	78	10.8	12,188,418	12,188,418	10,882	18,127	2019
2020	46	4,463	18.6	18.6	0.0	0.0	0.0	0.0	0.0	0.0	28,937	2,669	0	31,606	22,817	76	22,741	8,865	4,482	4,059	423	20.2	12,244,217	12,244,217	9,229	20,051	2020
2021	11	4,474	17.4	36.1	0.0	0.0	0.0	0.0	0.0	0.0	28,427	2,689	0	31,116	22,233	146	22,086	9,029	4,510	4,078	432	20.4	12,121,702	12,121,702	8,435	20,162	2021
2022	11	4,485	15.3	51.3	10.4	10.4	36.9	36.9	76.3	76.3	28,122	2,881	1,314	32,317	22,367	251	22,116	10,201	4,660	4,104	556	23.6	12,486,557	12,486,557	8,660	20,773	2022
2023	(699)	3,786	11.4	62.7	2.1	12.4	18.5	55.4	101.7	178.0	23,660	2,943	2,276	28,879	22,332	304	22,028	6,851	4,094	4,088	7	9.1	7,084,506	7,084,506	5,040	11,522	2023
2024	(100)	3,686	16.5	79.2	2.5	14.9	0.0	55.4	76.3	254.3	23,545	2,963	2,609	29,117	22,270	377	21,892	7,224	4,090	4,090	0	8.9	6,919,992	6,919,992	4,920	11,149	2024
2025	(50)	3,636	2.2	81.4	0.8	15.7	0.0	55.4	76.3	330.6	22,737	2,967	2,920	28,624	22,277	392	21,885	6,739	4,119	4,082	37	9.8	7,048,181	7,048,181	4,995	11,481	2025
2026	0	3,636	8.6	90.1	0.8	16.6	0.0	55.4	76.3	406.8	22,688	2,961	3,242	28,891	22,270	431	21,838	7,053	4,205	4,082	123	12.1	5,952,319	5,952,319	2,233	9,490	2026
2027	0	3,636	7.2	97.3	0.8	17.4	18.5	73.8	76.3	483.1	22,604	2,980	4,096	29,680	22,257	465	21,792	7,888	4,308	4,081	226	14.9	5,964,764	5,964,764	2,234	9,513	2027
2028	(391)	3,245	19.2	116.5	1.2	18.6	18.5	92.3	152.6	635.7	26,002	2,829	5,292	34,123	22,304	490	21,815	12,308	4,108	4,104	4	9.0	5,754,443	7,277,330	2,171	9,371	2028
2029	(107)	3,138	13.0	129.5	1.7	20.3	18.5	110.7	76.3	712.0	21,879	2,589	6,127	30,595	22,375	489	21,886	8,709	4,110	4,110	0	8.9	725,348	2,164,823	798	467	2029
2030	0	3,138	16.6	146.1	1.7	21.9	0.0	110.7	76.3	788.3	21,658	2,415	6,449	30,522	22,395	505	21,890	8,632	4,205	4,119	86	11.1	705,266	2,107,339	787	453	2030
2031	0	3,138	20.0	166.1	1.7	23.6	18.5	129.2	76.3	864.5	20,434	2,394	7,303	30,131	22,432	531	21,901	8,230	4,321	4,130	191	13.9	681,402	1,942,183	761	438	2031
2032	(13)	3,125	21.3	187.4	1.7	25.3	18.5	147.6	0.0	864.5	21,500	2,412	7,866	31,778	22,482	562	21,920	9,858	4,350	4,154	196	14.0	695,758	1,972,145	768	447	2032
2033	0	3,125	20.4	207.8	2.5	27.7	18.5	166.1	0.0	864.5	21,145	2,090	8,368	31,602	22,543	596	21,948	9,654	4,391	4,157	234	15.0	686,265	1,901,024	738	441	2033
2034	(247)	2,878	14.6	222.4	2.1	29.8	18.5	184.5	0.0	864.5	22,604	2,048	8,900	33,552	22,612	603	22,010	11,542	4,179	4,179	0	8.9	691,106	3,053,667	754	444	2034
2035	0	2,878	17.2	239.6	1.7	31.5	18.5	203.0	0.0	864.5	16,305	1,408	9,432	27,145	22,676	615	22,061	5,084	4,217	4,193	23	9.5	700,076	3,018,080	754	448	2035
2036	(7)	2,871	9.8	249.4	1.7	33.1	18.5	221.4	0.0	864.5	14,994	1,378	10,006	26,378	22,727	600	22,128	4,251	4,239	4,217	22	9.4	674,905	2,841,830	740	434	2036
2037	28	2,899	(23.3)	226.1	1.7	34.8	18.5	239.9	0.0	864.5	19,610	1,374	10,496	31,480	22,774	574	22,200	9,279	4,264	4,217	47	10.1	687,037	4,323,725	742	441	2037
2038	0	2,899	40.2	266.3	1.7	36.4	18.5	258.3	0.0	864.5	9,990	1,382	11,028	22,400	22,831	561	22,270	130	4,325	4,231	94	11.3	695,223	4,291,414	757	446	2038
2039	0	2,899	7.7	274.0	2.1	38.5	0.0	258.3	0.0	864.5	9,925	1,382	11,028	22,335	22,895	543	22,352	(17)	4,334	4,245	89	11.2	693,847	4,266,379	750	445	2039
2040	(56)	2,843	5.7	279.7	1.7	40.2	0.0	258.3	0.0	864.5	9,505	1,150	11,081	21,735	22,945	520	22,425	(690)	4,286	4,276	10	9.1	436,977	3,856,279	517	281	2040
2041	(50)	2,793	38.1	317.8	2.1	42.2	0.0	258.3	0.0	864.5	8,175	754	11,028	19,957	22,987	622	22,366	(2,408)	4,276	4,276	0	8.9	0	2,935,756	0	0	2041
2042	0	2,793	11.1	329.0	2.1	44.3	0.0	258.3	0.0	864.5	7,849	754	11,028	19,632	23,030	621	22,409	(2,777)	4,289	4,288	1	8.9	0	2,816,900	0	0	2042
2043	0	2,793	10.9	339.8	2.1	46.4	0.0	258.3	0.0	864.5	6,886	755	11,028	18,670	23,079	672	22,407	(3,737)	4,302	4,299	3	8.9	0	2,465,927	0	0	2043
2044	0	2,793	17.7	357.5	2.5	48.9	0.0	258.3	0.0	864.5	6,918	756	11,080	18,754	23,125	750	22,375	(3,621)	4,322	4,322	0	8.9	0	2,476,965	0	0	2044
2045	0	2,793	4.2	361.7	2.5	51.3	0.0	258.3	0.0	864.5	5,720	756	11,028	17,504	23,177	778	22,398	(4,894)	4,329	4,329	0	8.9	0	2,040,919	0	0	2045
2046	50	2,843	(10.7)	351.0	2.5	53.8	0.0	258.3	0.0	864.5	5,388	720	11,028	17,136	23,238	748	22,490	(5,354)	4,371	4,341	30	9.6	0	1,920,384	0	0	2046
2047	0	2,843	(16.9)	334.1	2.9	56.7	0.0	258.3	0.0	864.5	5,059	605	11,028	16,693	23,296	721	22,575	(5,882)	4,357	4,353	3	9.0	0	1,800,635	0	0	2047
2048	50	2,893	(44.9)	289.2	2.9	59.6	0.0	258.3	0.0	864.5	5,001	607	11,078	16,685	23,081	600	22,481	(5,796)	4,365	4,365	0	8.9	0	1,779,197	0	0	2048

Indiana & Michigan POWER COMPANY
INTEGRATED RESOURCE PLAN

RP1 retires (12/31/2028) & RP2 no lease extension (12/31/2022) CASE 2
High Band Commodity Pricing

	Utility Costs (Nominal$000)								
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(1)thru(7)-(8)
	Load Cost	Fuel Costs	Emission Costs	Existing System FOM + OGC	(Incremental) Fixed + Variable + Lease Costs +ST PPA	(Incremental) Capital + Renewable + VVO Program Costs	Contract (Revenue)/Cost	*Less:* Market Revenue	GRAND TOTAL, Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000
2019	712,206	381,891	25,769	29,683	194,170	0	39,467	810,325	572,861
2020	695,872	373,920	24,635	35,392	205,329	8,072	39,438	903,397	479,263
2021	700,627	370,725	24,634	40,613	205,794	8,139	37,637	922,587	465,582
2022	738,574	389,214	25,063	50,293	213,424	61,697	30,496	1,002,667	506,095
2023	773,622	245,702	12,963	37,520	95,138	118,876	26,054	923,072	386,802
2024	811,011	254,747	13,566	49,700	98,189	160,630	23,298	1,001,068	410,073
2025	837,160	258,779	13,808	41,771	98,079	204,874	22,608	1,034,205	442,874
2026	864,259	241,568	13,761	44,934	106,177	247,500	18,165	1,110,721	425,644
2027	897,078	252,569	13,891	45,395	111,541	290,164	15,468	1,185,700	440,406
2028	1,099,444	388,544	101,876	50,938	135,596	430,053	4,222	1,651,311	559,361
2029	1,111,190	236,955	18,779	38,228	137,913	477,244	(2,687)	1,494,935	522,686
2030	1,136,484	241,357	18,939	38,228	145,037	523,004	(12,903)	1,563,243	526,903
2031	1,155,208	226,761	17,511	38,228	148,330	568,918	(12,496)	1,574,403	568,058
2032	1,182,659	237,642	18,110	38,228	160,548	611,403	(13,093)	1,703,083	532,414
2033	1,210,367	236,878	17,824	38,228	165,618	643,782	(19,763)	1,746,111	546,824
2034	1,241,482	349,356	35,995	38,228	179,604	739,204	(21,734)	1,870,580	691,556
2035	1,286,934	304,825	35,708	38,228	150,846	741,314	(30,521)	1,572,002	955,333
2036	1,307,137	292,154	35,011	38,228	150,843	741,103	(30,347)	1,532,020	1,002,108
2037	1,351,345	483,399	62,745	38,228	185,487	895,066	(31,241)	1,869,404	1,115,625
2038	1,390,835	416,345	62,911	38,228	139,457	894,812	(34,436)	1,330,698	1,577,456
2039	1,422,436	411,107	62,197	33,438	143,742	895,368	(38,040)	1,330,507	1,599,741
2040	1,447,195	389,690	59,487	29,682	153,669	919,827	(48,527)	1,316,782	1,634,241
2041	1,484,631	363,955	55,093	23,561	154,388	927,413	(49,524)	1,290,872	1,668,645
2042	1,531,843	363,725	54,706	14,524	159,483	908,782	(50,953)	1,314,536	1,667,574
2043	1,559,613	327,260	49,249	12,155	162,781	915,895	(51,720)	1,277,790	1,697,444
2044	1,612,989	323,454	48,279	9,631	168,434	927,841	(53,375)	1,300,285	1,736,967
2045	1,666,853	313,384	46,594	7,674	173,126	916,883	(55,010)	1,311,832	1,757,672
2046	1,716,725	296,062	43,886	5,623	182,358	897,068	(53,736)	1,304,250	1,783,736
2047	1,746,070	268,072	40,012	3,136	187,390	907,255	(45,671)	1,278,363	1,827,900
2048	1,774,260	287,475	43,049	0	200,331	871,632	(46,982)	1,315,150	1,814,615

Indiana & Michigan POWER COMPANY
INTEGRATED RESOURCE PLAN
RP1 retires (12/31/2028) & RP2 no lease extension (12/31/2022) CASE 2 High Band Commodity Pricing

Resource (Capacity) Additions

	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
	(Current and Planned) Supply-Side + Purchased Unforced Capacity (UCAP)		(Increm) EE+ VVO + DR + Battery		Distributed Solar		Generic Wind		Utility Solar	
	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW
2019	4,417	4,417	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2020	46	4,463	18.6	18.6	0.0	0.0	0.0	0.0	0.0	0.0
2021	11	4,474	17.4	36.1	0.0	0.0	0.0	0.0	0.0	0.0
2022	11	4,485	15.3	51.3	10.4	10.4	36.9	36.9	76.3	76.3
2023	(699)	3,786	11.5	62.8	2.1	12.4	36.9	73.8	76.3	152.6
2024	(100)	3,686	9.1	71.9	2.5	14.9	18.5	92.3	76.3	228.9
2025	(50)	3,636	9.8	81.7	0.8	15.7	18.5	110.7	76.3	305.1
2026	0	3,636	8.6	90.3	0.8	16.6	18.5	129.2	76.3	381.4
2027	0	3,636	7.2	97.4	0.8	17.4	18.5	147.6	76.3	457.7
2028	(391)	3,245	17.6	115.0	1.2	18.6	18.5	166.1	101.7	559.4
2029	(107)	3,138	(0.7)	114.3	1.7	20.3	18.5	184.5	101.7	661.1
2030	0	3,138	24.3	138.6	1.7	21.9	18.5	203.0	76.3	737.4
2031	0	3,138	20.1	158.8	1.7	23.6	18.5	221.4	76.3	813.7
2032	(13)	3,125	21.4	180.2	1.7	25.3	18.5	239.9	50.9	864.5
2033	0	3,125	20.4	200.6	2.5	27.7	18.5	258.3	0.0	864.5
2034	(247)	2,878	12.7	213.4	2.1	29.8	0.0	258.3	0.0	864.5
2035	0	2,878	19.1	232.4	1.7	31.5	0.0	258.3	0.0	864.5
2036	(7)	2,871	11.2	243.7	1.7	33.1	0.0	258.3	0.0	864.5
2037	28	2,899	(22.3)	221.4	1.7	34.8	0.0	258.3	0.0	864.5
2038	0	2,899	42.4	263.8	1.7	36.4	0.0	258.3	0.0	864.5
2039	0	2,899	8.7	272.5	2.1	38.5	0.0	258.3	0.0	864.5
2040	(56)	2,843	9.3	281.7	1.7	40.2	0.0	258.3	0.0	864.5
2041	(50)	2,793	36.1	317.9	2.1	42.2	0.0	258.3	0.0	864.5
2042	0	2,793	9.7	327.5	2.1	44.3	0.0	258.3	0.0	864.5
2043	0	2,793	9.4	336.9	2.1	46.4	0.0	258.3	0.0	864.5
2044	0	2,793	20.6	357.5	2.5	48.9	0.0	258.3	0.0	864.5
2045	0	2,793	4.1	361.7	2.5	51.3	0.0	258.3	0.0	864.5
2046	50	2,843	(17.8)	343.8	2.5	53.8	0.0	258.3	0.0	864.5
2047	0	2,843	(9.2)	334.6	2.9	56.7	0.0	258.3	0.0	864.5
2048	50	2,893	(45.4)	289.2	2.9	59.6	0.0	258.3	0.0	864.5

Energy & Capacity Positions / Carbon Output

	(20)	(21)	(22)	(23)=(20)+(21)+(22)	(24)	(25)	(26)=(24)-(25)	(27)=(23)-(26)	(28)	(29)	(30)=(28)-(29)	(31)	(32)	(33)	
	Thermal Generation + Hydro	(Current) Purchased Energy Including OVEC	(New) Generic Wind + Utility Solar	= Market Sales	Load (Net of Embedded EE)	*Less:* (Increm) Energy Efficiency+ VVO+Dist Solar	= Net Load Requirements	ENERGY Surplus	Capacity	Peak + Reserves	CAPACITY Surplus	Reserve Margin	Existing Units CO2 Emissions	Total System CO2	
	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	%	tons	tons	
2019	26,960	2,735	0	29,695	23,943	0	23,943	5,752	4,417	4,339	78	10.8	12,969,251	12,969,251	2019
2020	29,138	2,702	0	31,841	22,817	76	22,741	9,100	4,482	4,059	423	20.2	12,491,918	12,491,918	2020
2021	28,728	2,735	0	31,463	22,233	146	22,086	9,376	4,510	4,078	432	20.4	12,479,562	12,479,562	2021
2022	28,336	2,932	1,314	32,582	22,367	251	22,116	10,466	4,660	4,104	556	23.6	12,751,919	12,751,919	2022
2023	23,551	2,988	2,628	29,167	22,332	305	22,027	7,140	4,088	4,088	0	8.9	6,822,687	6,822,687	2023
2024	23,535	3,003	3,499	30,037	22,270	349	21,921	8,117	4,094	4,090	4	9.0	6,919,548	6,919,548	2024
2025	22,704	3,002	4,337	30,043	22,277	393	21,884	8,160	4,149	4,082	67	10.7	6,991,591	6,991,591	2025
2026	22,664	2,992	5,191	30,847	22,270	433	21,837	9,010	4,253	4,082	171	13.4	5,986,610	5,986,610	2026
2027	22,553	2,995	6,045	31,594	22,257	466	21,791	9,803	4,356	4,081	275	16.2	5,974,969	5,974,969	2027
2028	25,516	2,915	7,038	35,469	22,304	499	21,806	13,663	4,104	4,104	0	8.9	5,856,305	7,286,564	2028
2029	21,588	2,696	7,969	32,253	22,375	457	21,917	10,335	4,118	4,110	8	9.1	844,384	2,177,699	2029
2030	21,376	2,526	8,823	32,725	22,395	504	21,891	10,833	4,239	4,119	120	12.0	828,991	2,128,203	2030
2031	20,159	2,523	9,677	32,360	22,432	531	21,902	10,458	4,355	4,130	225	14.8	824,828	1,985,495	2031
2032	21,180	2,528	10,469	34,177	22,482	562	21,920	12,257	4,435	4,154	281	16.2	825,206	1,984,949	2032
2033	20,838	2,220	10,956	34,015	22,543	596	21,948	12,067	4,476	4,157	319	17.2	831,173	1,934,040	2033
2034	22,025	2,164	10,956	35,145	22,612	596	22,016	13,129	4,244	4,179	65	10.6	819,093	2,970,926	2034
2035	15,604	1,517	10,956	28,077	22,676	615	22,060	6,017	4,265	4,193	72	10.7	820,549	2,883,044	2035
2036	14,409	1,511	11,004	26,925	22,727	607	22,120	4,804	4,271	4,217	53	10.2	822,158	2,775,992	2036
2037	18,915	1,504	10,956	31,375	22,774	591	22,183	9,192	4,278	4,217	61	10.4	831,593	4,214,755	2037
2038	9,115	1,500	10,956	21,571	22,831	585	22,246	(675)	4,322	4,231	91	11.2	825,641	4,103,065	2038
2039	8,712	1,500	10,956	21,168	22,895	572	22,323	(1,155)	4,333	4,245	88	11.1	824,839	3,955,478	2039
2040	8,060	1,287	11,009	20,356	22,945	559	22,387	(2,031)	4,288	4,276	12	9.2	589,443	3,482,432	2040
2041	7,222	754	10,956	18,932	22,987	650	22,337	(3,405)	4,276	4,276	0	8.9	0	2,588,697	2041
2042	6,934	754	10,956	18,645	23,030	644	22,387	(3,742)	4,288	4,288	0	8.9	0	2,483,584	2042
2043	6,047	755	10,956	17,758	23,079	676	22,403	(4,645)	4,299	4,299	0	8.9	0	2,160,248	2043
2044	5,734	756	11,008	17,497	23,125	751	22,374	(4,877)	4,322	4,322	0	8.9	0	2,046,055	2044
2045	5,354	756	10,956	17,066	23,177	779	22,398	(5,331)	4,329	4,329	0	8.9	0	1,907,893	2045
2046	4,882	720	10,956	16,558	23,238	748	22,489	(5,931)	4,363	4,341	23	9.4	0	1,736,215	2046
2047	4,314	605	10,956	15,875	23,296	723	22,572	(6,698)	4,357	4,353	4	9.0	0	1,529,441	2047
2048	4,480	607	11,006	16,092	23,081	601	22,480	(6,388)	4,365	4,365	0	8.9	0	1,589,884	2048

Indiana & Michigan POWER COMPANY
INTEGRATED RESOURCE PLAN

RP1 retires (12/31/2028) & RP2 no lease extension (12/31/2022) CASE 3
Low Band Commodity Pricing

	Utility Costs (Nominal$000)								
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(1)thru(7)-(8)
	Load Cost	Fuel Costs	Emission Costs	Existing System FOM + OGC	(Incremental) Fixed + Variable + Lease Costs +ST PPA	(Incremental) Capital + Renewable + VVO Program Costs	Contract (Revenue)/Cost	*Less:* Market Revenue	GRAND TOTAL, Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000
2019	638,663	322,446	20,270	29,683	191,406	0	47,966	676,415	574,020
2020	602,499	330,500	20,705	35,392	203,407	8,072	50,413	745,773	505,215
2021	578,002	291,775	17,770	40,613	202,216	7,559	52,577	690,071	500,441
2022	597,752	342,662	23,343	50,293	210,062	45,739	48,714	786,197	532,368
2023	620,536	230,701	13,279	37,520	97,598	80,110	46,374	716,499	409,618
2024	641,656	231,042	13,103	49,700	100,402	80,574	45,972	740,694	421,754
2025	662,295	237,306	13,639	41,771	97,865	99,018	45,951	750,698	447,146
2026	678,480	224,849	13,773	44,934	102,930	99,202	42,899	774,204	432,863
2027	701,611	235,909	13,926	45,395	105,167	114,270	41,646	817,870	440,055
2028	895,231	363,620	93,011	50,938	134,516	251,894	30,207	1,235,225	584,192
2029	901,216	266,423	31,499	38,228	138,314	266,370	21,763	1,117,381	546,432
2030	912,621	267,620	31,138	38,228	143,205	282,835	11,508	1,132,554	554,600
2031	925,318	252,522	28,906	38,228	145,093	297,658	12,433	1,106,353	593,805
2032	946,971	265,793	30,367	38,228	157,464	313,329	12,394	1,190,110	574,437
2033	965,304	263,289	29,693	38,228	164,303	327,836	3,363	1,205,805	586,212
2034	996,293	355,461	50,299	38,228	181,568	437,812	939	1,334,612	725,989
2035	1,027,816	312,088	50,246	38,228	155,556	456,848	(13,633)	1,098,232	928,917
2036	1,048,902	307,806	51,031	38,228	157,056	471,273	(13,699)	1,081,034	979,564
2037	1,079,952	452,672	79,290	38,228	191,794	625,246	(13,867)	1,342,015	1,111,301
2038	1,115,707	388,887	80,392	38,228	145,988	625,303	(16,946)	914,452	1,463,107
2039	1,138,960	391,338	80,913	33,438	150,605	657,242	(20,229)	942,486	1,489,781
2040	1,192,900	408,688	85,345	29,682	156,616	699,702	(35,404)	1,028,498	1,509,031
2041	1,233,476	391,343	81,011	23,561	159,164	688,217	(41,523)	1,010,700	1,524,549
2042	1,258,737	386,871	79,529	14,524	163,380	691,082	(42,205)	1,003,533	1,548,384
2043	1,270,372	356,407	73,371	12,155	166,034	685,482	(42,463)	951,564	1,569,794
2044	1,311,053	358,491	72,884	9,631	171,656	692,804	(43,717)	964,148	1,608,655
2045	1,351,673	349,653	70,747	7,674	175,746	684,879	(44,927)	961,411	1,634,034
2046	1,392,968	344,301	69,538	5,623	181,468	699,103	(43,912)	962,411	1,686,679
2047	1,418,907	324,307	65,952	3,136	186,985	705,439	(37,283)	942,533	1,724,910
2048	1,446,312	316,923	64,631	0	193,197	671,660	(38,471)	942,186	1,712,065

Indiana & Michigan POWER COMPANY
INTEGRATED RESOURCE PLAN
RP1 retires (12/31/2028) & RP2 no lease extension (12/31/2022) CASE 3 Low Band Commodity Pricing

	Resource (Capacity) Additions										Energy & Capacity Positions												Carbon Output		
	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)=(20)+(21)+(22)	(24)	(25)	(26)=(24)-(25)	(27)=(23)-(26)	(28)	(29)	(30)=(28)-(29)	(31)	(32)	(33)	
	(Current and Planned) Supply-Side + Purchased Unforced Capacity (UCAP)		(Increm) EE+ VVO + DR + Battery		Distributed Solar		Generic Wind		Utility Solar		Thermal Generation + Hydro	(Current) Purchased Energy Including OVEC	(New) Generic Wind + Utility Solar	= Market Sales	Load (Net of Embedded EE)	*Less:* (Increm) Energy Efficiency+ VVO+Dist Solar	= Net Load Requirements	ENERGY Surplus	Capacity	Peak + Reserves	CAPACITY Surplus	Reserve Margin	Existing Units CO2 Emissions	Total System CO2	
	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	%	tons	tons	
2019	4,417	4,417	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	24,432	2,660	0	27,091	23,943	0	23,943	3,148	4,417	4,339	78	10.8	10,285,926	10,285,926	2019
2020	46	4,463	18.6	18.6	0.0	0.0	0.0	0.0	0.0	0.0	27,420	2,595	0	30,015	22,817	76	22,741	7,274	4,482	4,059	423	20.2	10,536,476	10,536,476	2020
2021	11	4,474	16.4	35.1	0.0	0.0	0.0	0.0	0.0	0.0	25,605	2,564	0	28,168	22,233	141	22,092	6,077	4,509	4,078	431	20.4	9,047,119	9,047,119	2021
2022	11	4,485	13.2	48.2	10.4	10.4	36.9	36.9	0.0	0.0	27,542	2,805	992	31,339	22,367	234	22,133	9,206	4,580	4,104	477	21.5	11,786,419	11,786,419	2022
2023	(599)	3,886	9.3	57.6	2.1	12.4	18.5	55.4	76.3	76.3	23,549	2,884	1,846	28,279	22,332	277	22,055	6,224	4,088	4,088	0	8.9	6,854,521	6,854,521	2023
2024	0	3,886	8.2	65.8	2.5	14.9	0.0	55.4	0.0	76.3	23,352	2,899	1,856	28,106	22,270	317	21,953	6,154	4,098	4,090	9	9.1	6,597,657	6,597,657	2024
2025	(100)	3,786	10.6	76.4	0.8	15.7	0.0	55.4	76.3	152.6	22,592	2,906	2,168	27,667	22,277	366	21,911	5,756	4,086	4,082	4	9.0	6,811,306	6,811,306	2025
2026	0	3,786	9.3	85.7	0.8	16.6	0.0	55.4	0.0	152.6	22,548	2,898	2,168	27,614	22,270	409	21,861	5,754	4,096	4,082	14	9.2	5,889,705	5,889,705	2026
2027	(100)	3,686	8.2	93.9	0.8	17.4	0.0	55.4	76.3	228.9	22,684	2,914	2,491	28,088	22,257	447	21,809	6,279	4,081	4,081	0	8.9	5,892,392	5,892,392	2027
2028	(56)	3,630	1.8	95.7	1.2	18.6	0.0	55.4	76.3	305.1	27,059	2,593	2,824	32,476	22,304	456	21,848	10,628	4,105	4,104	1	8.9	4,211,611	6,544,282	2028
2029	(57)	3,573	(10.2)	85.5	1.7	20.3	0.0	55.4	76.3	381.4	24,068	2,338	3,135	29,541	22,375	420	21,955	7,586	4,116	4,110	5	9.0	448,540	2,685,004	2029
2030	(50)	3,523	10.1	95.6	1.7	21.9	0.0	55.4	76.3	457.7	23,674	2,161	3,457	29,292	22,395	466	21,928	7,363	4,154	4,119	35	9.8	425,043	2,561,130	2030
2031	0	3,523	0.3	95.8	1.7	23.6	0.0	55.4	76.3	534.0	22,233	2,143	3,779	28,155	22,432	474	21,958	6,197	4,232	4,130	102	11.5	404,687	2,320,569	2031
2032	(13)	3,510	1.8	97.6	1.7	25.3	0.0	55.4	76.3	610.3	23,336	2,146	4,115	29,596	22,482	486	21,995	7,601	4,298	4,154	145	12.7	402,748	2,347,453	2032
2033	0	3,510	(0.4)	97.1	2.5	27.7	0.0	55.4	76.3	686.6	22,855	1,809	4,423	29,087	22,543	494	22,049	7,037	4,377	4,157	220	14.6	376,204	2,213,437	2033
2034	(247)	3,263	(2.7)	94.5	2.1	29.8	0.0	55.4	76.3	762.8	24,374	1,775	4,745	30,894	22,612	489	22,123	8,771	4,205	4,179	26	9.6	389,410	3,396,346	2034
2035	0	3,263	(0.5)	94.0	1.7	31.5	0.0	55.4	76.3	839.1	17,910	1,121	5,067	24,097	22,676	474	22,202	1,896	4,283	4,193	90	11.2	383,237	3,285,444	2035
2036	(7)	3,256	18.0	112.0	1.7	33.1	0.0	55.4	25.4	864.5	16,864	1,110	5,190	23,163	22,727	490	22,237	926	4,321	4,217	104	11.5	377,863	3,225,746	2036
2037	28	3,284	(20.6)	91.4	1.7	34.8	0.0	55.4	0.0	864.5	21,364	1,106	5,175	27,644	22,774	472	22,302	5,342	4,330	4,217	113	11.8	390,728	4,666,026	2037
2038	0	3,284	40.2	131.6	1.7	36.4	0.0	55.4	0.0	864.5	11,615	1,118	5,175	17,908	22,831	466	22,365	(4,458)	4,372	4,231	141	12.5	403,672	4,591,802	2038
2039	0	3,284	8.6	140.2	2.1	38.5	18.5	73.8	0.0	864.5	11,299	1,107	5,707	18,113	22,895	452	22,443	(4,330)	4,401	4,245	156	12.9	390,780	4,463,506	2039
2040	(156)	3,128	10.6	150.8	1.7	40.2	18.5	92.3	0.0	864.5	11,513	992	6,265	18,769	22,945	448	22,497	(3,728)	4,276	4,276	0	8.9	262,538	4,413,074	2040
2041	0	3,128	(1.4)	149.4	2.1	42.2	0.0	92.3	0.0	864.5	10,565	754	6,239	17,558	22,987	429	22,558	(5,000)	4,276	4,276	0	8.9	0	3,806,496	2041
2042	0	3,128	12.3	161.6	2.1	44.3	0.0	92.3	0.0	864.5	10,028	754	6,239	17,021	23,030	445	22,585	(5,565)	4,291	4,288	3	8.9	0	3,610,503	2042
2043	0	3,128	7.5	169.2	2.1	46.4	0.0	92.3	0.0	864.5	8,951	755	6,239	15,944	23,079	471	22,609	(6,664)	4,300	4,299	1	8.9	0	3,218,312	2043
2044	0	3,128	19.5	188.7	2.5	48.9	0.0	92.3	0.0	864.5	8,598	756	6,264	15,618	23,125	516	22,609	(6,991)	4,322	4,322	0	8.9	0	3,088,840	2044
2045	0	3,128	10.4	199.1	2.5	51.3	0.0	92.3	0.0	864.5	8,070	756	6,239	15,065	23,177	566	22,611	(7,545)	4,335	4,329	6	9.0	0	2,896,892	2045
2046	0	3,128	19.8	218.8	2.5	53.8	0.0	92.3	0.0	864.5	7,669	720	6,239	14,627	23,238	598	22,640	(8,012)	4,357	4,341	17	9.3	0	2,751,087	2046
2047	0	3,128	19.6	238.4	2.9	56.7	0.0	92.3	0.0	864.5	7,036	605	6,239	13,880	23,296	629	22,667	(8,787)	4,380	4,353	27	9.5	0	2,520,978	2047
2048	0	3,128	(18.2)	220.2	2.9	59.6	0.0	92.3	0.0	864.5	6,669	607	6,262	13,537	23,081	553	22,528	(8,991)	4,365	4,365	0	8.9	0	2,386,938	2048

Indiana & Michigan POWER COMPANY
INTEGRATED RESOURCE PLAN

RP1 retires (12/31/2028) & RP2 no lease extension (12/31/2022) CASE 4 No Carbon Commodity Pricing

	Utility Costs (Nominal$000)								
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(1)thru(7)-(8)
	Load Cost	Fuel Costs	Emission Costs	Existing System FOM + OGC	(Incremental) Fixed + Variable + Lease Costs +ST PPA	(Incremental) Capital + Renewable + VVO Program Costs	Contract (Revenue)/Cost	*Less:* Market Revenue	GRAND TOTAL, Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000
2019	679,402	366,226	24,328	29,683	193,428	0	43,244	760,157	576,153
2020	653,133	368,427	24,136	35,392	205,081	8,072	44,501	844,154	494,587
2021	641,562	362,912	23,974	40,613	205,432	8,139	44,924	839,232	488,325
2022	673,278	372,477	24,660	50,293	210,769	45,606	39,027	898,686	517,424
2023	696,896	244,694	13,611	37,520	91,724	80,110	36,287	804,730	396,111
2024	726,278	247,260	13,640	49,700	95,048	80,140	34,672	840,826	405,912
2025	749,022	252,367	14,010	41,771	94,964	99,018	34,407	851,496	434,063
2026	771,429	234,392	13,770	44,934	100,318	99,416	30,553	886,378	408,434
2027	801,718	244,980	13,890	45,395	104,196	114,270	28,242	932,165	420,527
2028	816,693	414,574	14,202	50,938	133,494	251,894	29,890	1,155,112	556,573
2029	839,834	279,321	0	38,228	137,033	266,370	18,376	1,030,801	548,364
2030	865,852	286,678	0	38,228	143,006	282,835	5,799	1,070,989	551,409
2031	896,560	281,712	0	38,228	145,637	297,658	4,345	1,081,977	582,163
2032	932,061	300,206	0	38,228	158,274	313,329	2,356	1,184,947	559,508
2033	972,384	305,812	0	38,228	165,640	328,134	(9,597)	1,238,969	561,633
2034	1,005,774	439,798	0	38,228	184,540	438,071	(12,799)	1,403,316	690,297
2035	1,045,753	407,945	0	38,228	159,396	462,049	(28,226)	1,185,671	899,475
2036	1,059,905	406,554	0	38,228	160,964	468,621	(28,337)	1,163,500	942,434
2037	1,098,698	632,345	0	38,228	199,209	625,246	(29,545)	1,505,849	1,058,332
2038	1,149,207	594,150	0	38,228	154,735	625,125	(34,237)	1,110,564	1,416,645
2039	1,162,572	587,755	0	33,438	158,716	657,140	(36,993)	1,118,261	1,444,367
2040	1,188,564	603,165	0	29,682	164,468	698,350	(47,096)	1,169,987	1,467,146
2041	1,208,450	576,236	0	23,561	166,194	685,289	(40,529)	1,123,062	1,496,138
2042	1,227,456	563,869	0	14,524	169,720	688,095	(40,975)	1,101,442	1,521,248
2043	1,258,698	549,528	0	12,155	173,517	688,529	(41,925)	1,090,561	1,549,941
2044	1,295,892	561,071	0	9,631	179,465	692,771	(43,040)	1,108,734	1,587,057
2045	1,333,912	556,928	0	7,674	183,679	683,468	(44,160)	1,109,998	1,611,503
2046	1,378,248	542,048	0	5,623	188,767	699,103	(43,283)	1,104,239	1,666,267
2047	1,417,026	547,697	0	3,136	195,650	705,205	(37,163)	1,125,782	1,705,770
2048	1,433,367	530,056	0	0	201,282	671,660	(38,045)	1,106,933	1,691,387

Indiana & Michigan POWER COMPANY
INTEGRATED RESOURCE PLAN
RP1 retires (12/31/2028) & RP2 no lease extension (12/31/2022) CASE 4 No Carbon Commodity Pricing

	Resource (Capacity) Additions										Energy & Capacity Positions												Carbon Output		
	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)=(20)+(21)+(22)	(24)	(25)	(26)=(24)-(25)	(27)=(23)-(26)	(28)	(29)	(30)=(28)-(29)	(31)	(32)	(33)	
	(Current and Planned) Supply-Side + Purchased Unforced Capacity (UCAP)		(Increm) EE+ VVO + DR + Battery		Distributed Solar		Generic Wind		Utility Solar		Thermal Generation + Hydro	(Current) Purchased Energy Including OVEC	(New) Generic Wind + Utility Solar	= Market Sales	Load (Net of Embedded EE)	*Less:* (Increm) Energy Efficiency+ VVO+Dist Solar	= Net Load Requirements	ENERGY Surplus	Capacity	Peak + Reserves	CAPACITY Surplus	Reserve Margin	Existing Units CO2 Emissions	Total System CO2	
	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	%	tons	tons	
2019	4,417	4,417	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	26,284	2,712	0	28,996	23,943	0	23,943	5,053	4,417	4,339	78	10.8	12,254,837	12,254,837	2019
2020	46	4,463	18.6	18.6	0.0	0.0	0.0	0.0	0.0	0.0	28,918	2,669	0	31,587	22,817	76	22,741	8,847	4,482	4,059	423	20.2	12,219,263	12,219,263	2020
2021	11	4,474	17.4	36.1	0.0	0.0	0.0	0.0	0.0	0.0	28,416	2,688	0	31,104	22,233	146	22,086	9,018	4,510	4,078	432	20.4	12,109,829	12,109,829	2021
2022	11	4,485	12.9	48.9	10.4	10.4	36.9	36.9	0.0	0.0	28,145	2,883	992	32,021	22,367	238	22,129	9,892	4,581	4,104	478	21.5	12,515,281	12,515,281	2022
2023	(599)	3,886	9.2	58.1	2.1	12.4	18.5	55.4	76.3	76.3	23,653	2,942	1,846	28,441	22,332	280	22,052	6,389	4,088	4,088	1	8.9	7,071,093	7,071,093	2023
2024	0	3,886	7.5	65.7	2.5	14.9	0.0	55.4	0.0	76.3	23,532	2,961	1,856	28,349	22,270	316	21,953	6,396	4,098	4,090	8	9.1	6,906,841	6,906,841	2024
2025	(100)	3,786	10.6	76.2	0.8	15.7	0.0	55.4	76.3	152.6	22,732	2,965	2,168	27,865	22,277	365	21,912	5,953	4,086	4,082	3	9.0	7,040,059	7,040,059	2025
2026	0	3,786	9.6	85.8	0.8	16.6	0.0	55.4	0.0	152.6	22,708	2,960	2,168	27,837	22,270	410	21,860	5,977	4,096	4,082	14	9.3	5,951,807	5,951,807	2026
2027	(100)	3,686	8.1	93.9	0.8	17.4	0.0	55.4	76.3	228.9	22,591	2,978	2,491	28,060	22,257	448	21,809	6,251	4,082	4,081	0	8.9	5,954,235	5,954,235	2027
2028	(56)	3,630	1.8	95.7	1.2	18.6	0.0	55.4	76.3	305.1	27,678	2,981	2,824	33,483	22,304	456	21,848	11,635	4,105	4,104	1	8.9	5,932,346	8,058,756	2028
2029	(57)	3,573	(10.3)	85.4	1.7	20.3	0.0	55.4	76.3	381.4	23,748	2,769	3,135	29,652	22,375	419	21,956	7,696	4,115	4,110	5	9.0	926,566	3,046,778	2029
2030	(50)	3,523	10.1	95.5	1.7	21.9	0.0	55.4	76.3	457.7	23,571	2,609	3,457	29,636	22,395	466	21,928	7,708	4,154	4,119	35	9.8	921,865	3,020,508	2030
2031	0	3,523	0.3	95.8	1.7	23.6	0.0	55.4	76.3	534.0	22,510	2,614	3,779	28,902	22,432	474	21,958	6,944	4,232	4,130	102	11.5	926,175	2,942,821	2031
2032	(13)	3,510	1.8	97.6	1.7	25.3	0.0	55.4	76.3	610.3	23,738	2,627	4,115	30,480	22,482	486	21,995	8,484	4,298	4,154	145	12.7	935,647	3,027,042	2032
2033	0	3,510	(0.1)	97.4	2.5	27.7	0.0	55.4	76.3	686.6	23,507	2,316	4,423	30,247	22,543	496	22,048	8,199	4,377	4,157	220	14.6	938,974	3,013,804	2033
2034	(247)	3,263	(2.4)	95.0	2.1	29.8	0.0	55.4	76.3	762.8	25,795	2,264	4,745	32,804	22,612	492	22,120	10,684	4,206	4,179	27	9.6	930,947	4,455,888	2034
2035	0	3,263	6.6	101.6	1.7	31.5	0.0	55.4	76.3	839.1	19,600	1,612	5,067	26,279	22,676	476	22,200	4,079	4,291	4,193	97	11.4	927,148	4,445,177	2035
2036	(7)	3,256	14.3	115.9	1.7	33.1	0.0	55.4	25.4	864.5	18,600	1,619	5,190	25,410	22,727	492	22,235	3,174	4,325	4,217	108	11.7	943,042	4,423,455	2036
2037	28	3,284	(20.7)	95.2	1.7	34.8	0.0	55.4	0.0	864.5	24,648	1,604	5,175	31,426	22,774	474	22,301	9,126	4,334	4,217	117	11.9	943,148	6,414,857	2037
2038	0	3,284	40.0	135.2	1.7	36.4	0.0	55.4	0.0	864.5	15,429	1,598	5,175	22,201	22,831	466	22,365	(164)	4,376	4,231	145	12.6	935,009	6,512,609	2038
2039	0	3,284	8.5	143.7	2.1	38.5	18.5	73.8	0.0	864.5	14,754	1,595	5,707	22,056	22,895	451	22,444	(388)	4,405	4,245	159	13.0	931,292	6,262,764	2039
2040	(156)	3,128	7.1	150.8	1.7	40.2	18.5	92.3	0.0	864.5	14,783	1,426	6,265	22,474	22,945	435	22,510	(36)	4,276	4,276	0	8.9	742,874	6,085,556	2040
2041	0	3,128	(0.8)	150.0	2.1	42.2	0.0	92.3	0.0	864.5	13,495	754	6,239	20,487	22,987	431	22,556	(2,069)	4,277	4,276	1	8.9	0	4,873,320	2041
2042	0	3,128	8.6	158.6	2.1	44.3	0.0	92.3	0.0	864.5	12,672	754	6,239	19,665	23,030	447	22,583	(2,918)	4,288	4,288	0	8.9	0	4,573,170	2042
2043	0	3,128	11.0	169.7	2.1	46.4	0.0	92.3	0.0	864.5	11,944	755	6,239	18,938	23,079	473	22,607	(3,669)	4,301	4,299	2	8.9	0	4,307,636	2043
2044	0	3,128	19.0	188.6	2.5	48.9	0.0	92.3	0.0	864.5	11,660	756	6,264	18,680	23,125	516	22,609	(3,929)	4,322	4,322	0	8.9	0	4,203,704	2044
2045	0	3,128	4.2	192.9	2.5	51.3	0.0	92.3	0.0	864.5	11,121	756	6,239	18,116	23,177	544	22,633	(4,517)	4,329	4,329	0	8.9	0	4,007,311	2045
2046	0	3,128	26.2	219.0	2.5	53.8	0.0	92.3	0.0	864.5	10,423	720	6,239	17,382	23,238	599	22,639	(5,257)	4,358	4,341	17	9.3	0	3,752,845	2046
2047	0	3,128	19.4	238.5	2.9	56.7	0.0	92.3	0.0	864.5	10,234	605	6,239	17,078	23,296	629	22,667	(5,589)	4,380	4,353	27	9.5	0	3,684,215	2047
2048	0	3,128	(18.2)	220.2	2.9	59.6	0.0	92.3	0.0	864.5	9,598	607	6,262	16,467	23,081	553	22,528	(6,061)	4,365	4,365	0	8.9	0	3,452,299	2048

Indiana & Michigan POWER COMPANY
INTEGRATED RESOURCE PLAN

RP1 FGD (12/31/2025) RP1 Retires (12/31/2044) & RP2 no lease extension (12/31/2022) CASE 6 Base Band Commodity Pricing

	Utility Costs (Nominal$000)								
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(1)thru(7)-(8)
	Load Cost	Fuel Costs	Emission Costs	Existing System FOM + OGC	(Incremental) Fixed + Variable + Lease Costs +ST PPA	(Incremental) Capital + Renewable + VVO Program Costs	Contract (Revenue)/Cost	*Less:* Market Revenue	GRAND TOTAL, Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000
2019	678,067	364,680	24,194	29,683	193,358	0	43,454	757,369	576,067
2020	653,672	368,811	24,193	35,392	205,101	6,054	44,472	844,686	493,010
2021	642,024	363,181	23,997	40,613	205,444	6,141	44,899	839,343	486,956
2022	670,720	372,595	24,605	50,293	211,172	50,640	39,407	895,193	524,238
2023	697,906	245,732	13,638	37,520	96,036	86,282	36,237	806,253	407,098
2024	727,080	248,361	13,667	49,700	97,661	87,171	34,661	843,511	414,790
2025	750,837	234,310	12,381	41,771	94,519	93,776	34,270	827,122	434,741
2026	773,155	272,194	56,351	44,934	105,598	340,186	30,394	983,914	638,899
2027	802,988	294,875	60,588	45,395	108,928	405,661	28,154	1,063,715	682,874
2028	1,004,061	233,922	115,581	50,938	108,123	454,692	16,687	1,221,104	762,901
2029	1,011,147	243,534	119,247	50,616	118,403	468,672	9,422	1,278,092	742,949
2030	1,033,175	248,360	122,307	56,936	127,691	498,404	(1,100)	1,331,415	754,358
2031	1,050,471	252,736	141,236	58,034	131,355	513,262	(532)	1,359,015	787,547
2032	1,081,557	252,305	136,283	62,426	142,717	558,272	(1,460)	1,466,838	765,262
2033	1,105,223	257,908	140,831	64,060	149,934	603,931	(9,153)	1,530,029	782,705
2034	1,136,325	312,069	168,276	67,807	159,101	708,811	(11,466)	1,643,141	897,782
2035	1,181,663	286,117	188,587	69,734	132,366	744,322	(23,310)	1,442,285	1,137,194
2036	1,190,603	252,695	160,475	55,879	130,405	520,384	(22,291)	1,367,825	920,325
2037	1,226,123	453,259	232,822	55,879	167,616	705,439	(22,629)	1,779,993	1,038,516
2038	1,270,871	380,482	223,190	55,879	120,813	736,913	(26,369)	1,314,991	1,446,789
2039	1,305,270	409,736	252,919	51,088	126,853	768,808	(30,265)	1,412,530	1,471,880
2040	1,330,720	392,442	238,435	47,333	132,506	806,453	(42,017)	1,424,136	1,481,735
2041	1,350,531	378,241	247,304	41,212	135,970	806,701	(45,067)	1,403,576	1,511,316
2042	1,388,191	349,994	214,498	32,175	135,783	809,784	(46,179)	1,364,764	1,519,481
2043	1,411,141	356,396	245,902	29,806	141,195	802,516	(46,790)	1,404,376	1,535,789
2044	1,466,439	374,840	262,038	27,282	147,843	803,137	(48,533)	1,473,890	1,559,156
2045	1,495,103	292,693	50,128	25,325	170,764	984,862	(49,290)	1,193,322	1,776,262
2046	1,541,599	285,677	48,820	23,274	176,912	988,237	(48,200)	1,201,664	1,814,653
2047	1,584,176	275,509	47,384	20,787	183,515	992,984	(41,360)	1,214,033	1,848,964
2048	1,606,514	280,862	48,459	17,651	190,926	960,242	(42,456)	1,235,611	1,826,586

Indiana & Michigan POWER COMPANY
INTEGRATED RESOURCE PLAN
RP1 FGD (12/31/2025) RP1 Retires (12/31/2044) & RP2 no lease extension (12/31/2022) CASE 6 Base Band Commodity Pricing

	Resource (Capacity) Additions										Energy & Capacity Positions												Carbon Output		
	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)=(20)+(21)+(22)	(24)	(25)	(26)=(24)-(25)	(27)=(23)-(26)	(28)	(29)	(30)=(28)-(29)	(31)	(32)	(33)	
	(Current and Planned) Supply-Side + Purchased Unforced Capacity (UCAP)		(Increm) EE+ VVO + DR + Battery		Distributed Solar		Generic Wind		Utility Solar		Thermal Generation + Hydro	(Current) Purchased Energy Including OVEC	(New) Generic Wind + Utility Solar	= Market Sales	Load (Net of Embedded EE)	*Less:* (Increm) Energy Efficiency+ VVO+Dist Solar	= Net Load Requirements	ENERGY Surplus	Capacity	Peak + Reserves	CAPACITY Surplus	Reserve Margin	Existing Units CO2 Emissions	Total System CO2	
	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	%	tons	tons	
2019	4,417	4,417	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	26,221	2,709	0	28,930	23,943	0	23,943	4,987	4,417	4,339	78	10.8	12,188,418	12,188,418	2019
2020	46	4,463	18.6	18.6	0.0	0.0	0.0	0.0	0.0	0.0	28,937	2,666	0	31,604	22,817	76	22,741	8,863	4,482	4,059	423	20.2	12,244,217	12,244,217	2020
2021	11	4,474	17.4	36.1	0.0	0.0	0.0	0.0	0.0	0.0	28,427	2,686	0	31,113	22,233	146	22,086	9,027	4,510	4,078	432	20.4	12,121,702	12,121,702	2021
2022	29	4,503	25.3	61.3	10.4	10.4	36.9	36.9	0.0	0.0	28,147	2,878	992	32,018	22,367	251	22,116	9,901	4,612	4,104	508	22.3	12,486,557	12,498,609	2022
2023	(599)	3,904	12.9	74.3	2.1	12.4	18.5	55.4	76.3	76.3	23,684	2,941	1,846	28,471	22,332	312	22,020	6,451	4,122	4,088	35	9.8	7,084,428	7,096,064	2023
2024	(50)	3,854	15.0	89.3	2.5	14.9	0.0	55.4	0.0	76.3	23,571	2,960	1,856	28,387	22,270	380	21,889	6,497	4,090	4,090	0	8.9	6,919,992	6,932,017	2024
2025	(32)	3,822	23.8	113.1	0.8	15.7	0.0	55.4	0.0	76.3	22,246	2,964	1,846	27,057	22,277	401	21,876	5,181	4,082	4,082	0	8.9	6,331,549	6,353,762	2025
2026	(83)	3,739	8.2	121.2	0.8	16.6	0.0	55.4	76.3	152.6	25,841	2,958	2,168	30,967	22,270	438	21,832	9,135	4,085	4,082	3	8.9	8,726,180	8,747,170	2026
2027	(100)	3,639	6.8	128.0	0.8	17.4	18.5	73.8	76.3	228.9	26,135	2,978	3,023	32,135	22,257	469	21,788	10,347	4,087	4,081	6	9.0	9,154,293	9,175,615	2027
2028	6	3,645	23.4	151.5	1.2	18.6	18.5	92.3	76.3	305.1	22,544	2,827	3,894	29,265	22,304	486	21,818	7,447	4,212	4,104	108	11.7	6,191,359	6,227,590	2028
2029	(6)	3,639	(10.4)	141.1	1.7	20.3	0.0	92.3	76.3	381.4	23,434	2,587	4,199	30,219	22,375	448	21,926	8,293	4,274	4,110	164	13.2	6,179,335	6,212,054	2029
2030	0	3,639	9.5	150.5	1.7	21.9	0.0	92.3	152.6	534.0	23,285	2,412	4,843	30,540	22,395	492	21,903	8,638	4,438	4,119	319	17.3	6,135,829	6,167,098	2030
2031	0	3,639	(0.8)	149.7	1.7	23.6	0.0	92.3	76.3	610.3	23,109	2,391	5,165	30,666	22,432	494	21,938	8,727	4,515	4,130	385	19.0	6,773,502	6,800,729	2031
2032	(13)	3,626	0.8	150.5	1.7	25.3	18.5	110.7	76.3	686.6	23,738	2,409	6,043	32,190	22,482	501	21,981	10,209	4,599	4,154	445	20.5	6,399,607	6,428,054	2032
2033	0	3,626	0.2	150.7	2.5	27.7	18.5	129.2	76.3	762.8	23,576	2,087	6,874	32,537	22,543	513	22,031	10,507	4,696	4,157	539	23.0	6,407,674	6,435,444	2033
2034	(632)	2,994	18.0	168.7	2.1	29.8	18.5	147.6	76.3	839.1	24,032	2,046	7,728	33,806	22,612	533	22,079	11,727	4,179	4,179	0	8.9	6,939,514	7,556,074	2034
2035	0	2,994	12.3	181.1	1.7	31.5	18.5	166.1	25.4	864.5	18,414	1,406	8,368	28,187	22,676	525	22,151	6,036	4,237	4,193	44	10.0	7,537,498	8,143,641	2035
2036	(7)	2,987	9.3	190.4	1.7	33.1	18.5	184.5	0.0	864.5	16,184	1,376	8,936	26,496	22,727	507	22,221	4,275	4,260	4,217	42	10.0	6,275,747	6,842,349	2036
2037	27	3,014	(22.1)	168.3	1.7	34.8	18.5	203.0	0.0	864.5	22,402	1,372	9,432	33,205	22,774	484	22,290	10,915	4,285	4,217	67	10.6	7,696,061	9,798,224	2037
2038	0	3,014	40.1	208.4	1.7	36.4	18.5	221.4	0.0	864.5	12,238	1,380	9,964	23,582	22,831	474	22,357	1,225	4,345	4,231	114	11.8	7,125,828	9,205,555	2038
2039	0	3,014	8.1	216.5	2.1	38.5	18.5	239.9	0.0	864.5	12,984	1,380	10,496	24,860	22,895	458	22,438	2,423	4,373	4,245	128	12.2	7,908,726	9,973,634	2039
2040	(105)	2,909	4.0	220.5	1.7	40.2	18.5	258.3	0.0	864.5	12,072	1,147	11,081	24,300	22,945	429	22,516	1,784	4,292	4,276	17	9.3	6,971,550	8,948,341	2040
2041	0	2,909	14.7	235.2	2.1	42.2	0.0	258.3	0.0	864.5	11,538	751	11,028	23,318	22,987	444	22,544	774	4,309	4,276	33	9.7	6,770,545	8,466,911	2041
2042	(50)	2,859	26.4	261.5	2.1	44.3	0.0	258.3	0.0	864.5	10,115	752	11,028	21,895	23,030	500	22,531	(635)	4,288	4,288	0	8.9	5,556,448	7,183,302	2042
2043	0	2,859	9.6	271.2	2.1	46.4	0.0	258.3	0.0	864.5	10,449	753	11,028	22,230	23,079	493	22,586	(356)	4,299	4,299	0	8.9	6,440,364	7,863,851	2043
2044	0	2,859	20.6	291.7	2.5	48.9	0.0	258.3	0.0	864.5	10,727	754	11,080	22,560	23,125	529	22,596	(36)	4,322	4,322	0	8.9	6,682,931	8,112,378	2044
2045	(12)	2,847	25.1	316.9	2.5	51.3	0.0	258.3	0.0	864.5	5,744	754	11,028	17,527	23,177	580	22,597	(5,071)	4,338	4,329	9	9.1	0	2,052,576	2045
2046	0	2,847	20.0	336.9	2.5	53.8	0.0	258.3	0.0	864.5	5,411	718	11,028	17,157	23,238	612	22,626	(5,469)	4,361	4,341	20	9.4	0	1,931,418	2046
2047	0	2,847	18.4	355.2	2.9	56.7	0.0	258.3	0.0	864.5	5,081	603	11,028	16,712	23,296	637	22,658	(5,946)	4,382	4,353	28	9.6	0	1,811,240	2047
2048	0	2,847	(20.0)	335.2	2.9	59.6	0.0	258.3	0.0	864.5	5,023	604	11,078	16,705	23,081	555	22,526	(5,821)	4,365	4,365	0	8.9	0	1,789,669	2048

Indiana & Michigan POWER COMPANY
INTEGRATED RESOURCE PLAN

RP1 FGD (12/31/2028) & RP2 no lease extension (12/31/2022) CASE 7
Base Band Commodity Pricing

	Utility Costs (Nominal$000)								
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(1)thru(7)-(8)
	Load Cost	Fuel Costs	Emission Costs	Existing System FOM + OGC	(Incremental) Fixed + Variable + Lease Costs +ST PPA	(Incremental) Capital + Renewable + VVO Program Costs	Contract (Revenue)/Cost	*Less:* Market Revenue	GRAND TOTAL, Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000
2019	678,067	364,680	24,194	29,683	193,358	0	43,454	757,369	576,067
2020	653,672	368,811	24,193	35,392	205,101	8,072	44,472	845,203	494,510
2021	642,024	363,181	23,997	40,613	205,444	8,139	44,899	840,334	487,964
2022	670,720	372,595	24,605	50,293	211,172	52,582	39,407	896,634	524,738
2023	697,906	245,732	13,638	37,520	96,036	88,265	36,237	808,117	407,218
2024	727,080	248,361	13,667	49,700	97,661	89,087	34,661	845,762	414,455
2025	750,837	254,094	14,032	41,771	95,177	96,634	34,270	846,960	439,854
2026	773,155	236,786	13,872	44,934	100,820	106,667	30,394	889,861	416,768
2027	802,988	247,141	13,920	45,395	103,601	123,297	28,154	936,029	428,468
2028	1,004,061	240,120	77,479	50,938	106,061	170,252	16,686	1,154,573	511,025
2029	1,011,147	239,259	115,353	50,616	117,221	461,187	9,422	1,269,731	734,474
2030	1,033,175	249,458	123,528	56,936	126,800	516,838	(1,100)	1,332,705	772,929
2031	1,050,471	252,651	141,132	58,034	130,381	559,781	(532)	1,385,011	806,908
2032	1,081,557	252,846	136,818	62,426	141,755	605,190	(1,460)	1,492,895	786,236
2033	1,105,223	258,279	140,964	64,060	148,912	650,446	(9,153)	1,555,958	802,773
2034	1,136,325	310,603	166,646	67,807	157,967	758,335	(11,466)	1,666,451	919,765
2035	1,181,663	286,371	188,847	69,734	132,383	795,038	(23,310)	1,473,729	1,156,998
2036	1,190,603	259,498	168,664	74,481	130,893	825,273	(22,291)	1,416,074	1,211,048
2037	1,226,123	456,689	236,836	76,004	167,844	1,010,385	(22,629)	1,819,073	1,332,180
2038	1,270,871	378,039	220,069	79,986	120,643	1,041,898	(26,369)	1,343,641	1,741,496
2039	1,305,270	409,355	252,455	59,441	126,828	801,437	(30,265)	1,445,010	1,479,511
2040	1,330,720	394,515	241,103	55,686	132,652	808,967	(42,017)	1,432,427	1,489,198
2041	1,350,531	380,451	250,286	49,564	136,117	809,407	(45,067)	1,411,013	1,520,276
2042	1,388,191	349,994	214,498	40,527	135,783	812,496	(46,179)	1,369,638	1,525,673
2043	1,411,141	356,396	245,902	38,158	141,195	805,183	(46,790)	1,409,805	1,541,379
2044	1,466,439	374,840	262,038	35,635	147,843	805,771	(48,533)	1,480,048	1,563,985
2045	1,495,103	292,693	50,128	33,678	170,764	987,853	(49,290)	1,200,133	1,780,794
2046	1,541,599	285,677	48,820	31,626	176,912	991,320	(48,200)	1,209,027	1,818,726
2047	1,584,176	275,509	47,384	29,140	183,515	996,053	(41,360)	1,221,647	1,852,771
2048	1,606,514	280,862	48,459	26,003	190,926	958,700	(42,456)	1,241,484	1,827,524

Indiana & Michigan POWER COMPANY
INTEGRATED RESOURCE PLAN
RP1 FGD (12/31/2028) & RP2 no lease extension (12/31/2022) CASE 7 Base Band Commodity Pricing

	Resource (Capacity) Additions										Energy & Capacity Positions												Carbon Output		NOX Output	SOX Output	
	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)=(20)+(21)+(22)	(24)	(25)	(26)=(24)-(25)	(27)=(23)-(26)	(28)	(29)	(30)=(28)-(29)	(31)	(32)	(33)			
	(Current and Planned) Supply-Side + Purchased Unforced Capacity (UCAP)		(Increm) EE+ VVO + DR + Battery		Distributed Solar		Generic Wind		Utility Solar		Thermal Generation + Hydro	(Current) Purchased Energy Including OVEC	(New) Generic Wind + Utility Solar	= Market Sales	Load (Net of Embedded EE)	Less: (Increm) Energy Efficiency+ VVO+Dist Solar	= Net Load Requirements	ENERGY Surplus	Capacity	Peak + Reserves	CAPACITY Surplus	Reserve Margin	Existing Units CO2 Emissions	Total System CO2	Total System Nox	Total System SO2	
	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	%	tons	tons	tons	tons	
2019	4,417	4,417	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	26,221	2,709	0	28,930	23,943	0	23,943	4,987	4,417	4,339	78	10.8	12,188,418	12,188,418	10,882	18,127	2019
2020	46	4,463	18.6	18.6	0.0	0.0	0.0	0.0	0.0	0.0	28,937	2,666	0	31,604	22,817	76	22,741	8,863	4,482	4,059	423	20.2	12,244,217	12,244,217	9,229	20,051	2020
2021	11	4,474	17.4	36.1	0.0	0.0	0.0	0.0	0.0	0.0	28,427	2,686	0	31,113	22,233	146	22,086	9,027	4,510	4,078	432	20.4	12,121,702	12,121,702	8,435	20,162	2021
2022	29	4,503	25.3	61.3	10.4	10.4	36.9	36.9	0.0	0.0	28,147	2,878	992	32,018	22,367	251	22,116	9,901	4,612	4,104	508	22.3	12,486,557	12,498,609	8,660	20,773	2022
2023	(599)	3,904	12.7	74.0	2.1	12.4	18.5	55.4	76.3	76.3	23,684	2,941	1,846	28,471	22,332	311	22,021	6,450	4,122	4,088	34	9.8	7,084,428	7,096,064	5,040	11,522	2023
2024	(50)	3,854	15.3	89.3	2.5	14.9	0.0	55.4	0.0	76.3	23,571	2,960	1,856	28,387	22,270	380	21,890	6,497	4,090	4,090	0	8.9	6,919,992	6,932,017	4,920	11,149	2024
2025	(32)	3,822	23.8	113.1	0.8	15.7	0.0	55.4	0.0	76.3	22,761	2,964	1,846	27,571	22,277	401	21,876	5,695	4,082	4,082	0	8.9	7,050,385	7,072,598	4,996	10,192	2025
2026	(50)	3,772	8.2	121.3	0.8	16.6	0.0	55.4	50.9	127.1	22,758	2,958	2,061	27,778	22,270	438	21,831	5,946	4,092	4,082	10	9.1	5,992,706	6,013,695	2,243	4,065	2026
2027	(100)	3,672	12.0	133.4	0.8	17.4	0.0	55.4	76.3	203.4	22,700	2,978	2,383	28,061	22,257	490	21,767	6,294	4,082	4,081	0	8.9	5,964,986	5,986,308	2,234	4,260	2027
2028	7	3,679	18.3	151.7	1.2	18.6	18.5	73.8	76.3	279.7	21,690	2,827	3,251	27,768	22,304	487	21,817	5,951	4,203	4,104	99	11.5	5,430,062	5,466,293	2,085	2,903	2028
2029	(40)	3,639	(9.6)	142.1	1.7	20.3	18.5	92.3	76.3	356.0	23,249	2,587	4,092	29,927	22,375	454	21,921	8,006	4,250	4,110	139	12.6	6,000,469	6,033,187	2,225	2,894	2029
2030	0	3,639	10.8	152.9	1.7	21.9	0.0	92.3	152.6	508.6	23,329	2,412	4,736	30,477	22,395	505	21,890	8,587	4,415	4,119	296	16.7	6,190,174	6,221,444	2,270	2,869	2030
2031	0	3,639	(0.8)	152.1	1.7	23.6	18.5	110.7	76.3	584.8	23,107	2,391	5,590	31,089	22,432	507	21,926	9,163	4,510	4,130	380	18.9	6,768,965	6,796,192	2,406	3,149	2031
2032	(13)	3,626	0.8	152.9	1.7	25.3	18.5	129.2	76.3	661.1	23,763	2,409	6,470	32,643	22,482	514	21,968	10,675	4,594	4,154	441	20.4	6,422,036	6,450,484	2,316	2,986	2032
2033	0	3,626	(0.1)	152.7	2.5	27.7	18.5	147.6	76.3	737.4	23,570	2,087	7,299	32,956	22,543	523	22,020	10,936	4,691	4,157	534	22.9	6,413,059	6,440,828	2,287	2,987	2033
2034	(632)	2,994	23.0	175.7	2.1	29.8	18.5	166.1	76.3	813.7	23,966	2,046	8,153	34,165	22,612	564	22,048	12,117	4,179	4,179	0	8.9	6,875,025	7,491,585	2,426	3,224	2034
2035	0	2,994	8.4	184.1	1.7	31.5	18.5	184.5	50.9	864.5	18,426	1,406	8,900	28,731	22,676	539	22,136	6,595	4,259	4,193	65	10.6	7,547,579	8,153,722	2,606	3,491	2035
2036	(7)	2,987	8.2	192.3	1.7	33.1	18.5	203.0	0.0	864.5	16,497	1,376	9,471	27,344	22,727	516	22,211	5,133	4,280	4,217	63	10.5	6,580,906	7,147,509	2,337	2,926	2036
2037	28	3,015	(23.2)	169.0	1.7	34.8	18.5	221.4	0.0	864.5	22,544	1,372	9,964	33,880	22,774	489	22,285	11,595	4,305	4,217	87	11.1	7,841,233	9,943,396	2,676	3,560	2037
2038	0	3,015	39.7	208.8	1.7	36.4	18.5	239.9	0.0	864.5	12,132	1,380	10,496	24,008	22,831	476	22,355	1,653	4,365	4,231	134	12.3	7,016,275	9,096,001	2,466	3,308	2038
2039	0	3,015	7.7	216.5	2.1	38.5	18.5	258.3	0.0	864.5	12,971	1,380	11,028	25,379	22,895	458	22,437	2,942	4,393	4,245	148	12.7	7,892,898	9,957,807	2,696	3,655	2039
2040	(106)	2,909	3.9	220.4	1.7	40.2	0.0	258.3	0.0	864.5	12,157	1,147	11,081	24,385	22,945	429	22,516	1,869	4,292	4,276	17	9.3	7,059,752	9,036,543	2,307	3,189	2040
2041	0	2,909	14.7	235.2	2.1	42.2	0.0	258.3	0.0	864.5	11,622	751	11,028	23,402	22,987	444	22,544	858	4,309	4,276	33	9.7	6,866,108	8,562,475	1,856	3,013	2041
2042	(50)	2,859	26.4	261.5	2.1	44.3	0.0	258.3	0.0	864.5	10,115	752	11,028	21,895	23,030	500	22,531	(635)	4,288	4,288	0	8.9	5,556,448	7,183,302	1,502	2,473	2042
2043	0	2,859	9.6	271.1	2.1	46.4	0.0	258.3	0.0	864.5	10,449	753	11,028	22,230	23,079	493	22,586	(356)	4,299	4,299	0	8.9	6,440,364	7,863,851	1,741	2,866	2043
2044	0	2,859	20.4	291.6	2.5	48.9	0.0	258.3	0.0	864.5	10,727	754	11,080	22,560	23,125	528	22,597	(37)	4,322	4,322	0	8.9	6,682,931	8,112,378	1,807	2,974	2044
2045	(12)	2,847	25.3	316.8	2.5	51.3	0.0	258.3	0.0	864.5	5,744	754	11,028	17,527	23,177	579	22,597	(5,071)	4,338	4,329	9	9.1	0	2,052,576	0	0	2045
2046	0	2,847	20.1	336.9	2.5	53.8	0.0	258.3	0.0	864.5	5,411	718	11,028	17,157	23,238	612	22,626	(5,469)	4,361	4,341	20	9.4	0	1,931,418	0	0	2046
2047	0	2,847	18.3	355.2	2.9	56.7	0.0	258.3	0.0	864.5	5,081	603	11,028	16,712	23,296	637	22,658	(5,946)	4,382	4,353	28	9.6	0	1,811,240	0	0	2047
2048	0	2,847	(20.0)	335.2	2.9	59.6	0.0	258.3	0.0	864.5	5,023	604	11,078	16,705	23,081	555	22,526	(5,821)	4,365	4,365	0	8.9	0	1,789,669	0	0	2048

Indiana & Michigan POWER COMPANY
INTEGRATED RESOURCE PLAN

RP1 retires (12/31/2028) & RP2 lease extension + RP 2 FGD (12/31/2028) + RP2 Retirement (12/31/2048) CASE 8 Base Band Commodity Pricing

	Utility Costs (Nominal$000)								
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(1)thru(7)-(8)
	Load Cost	Fuel Costs	Emission Costs	Existing System FOM + OGC	(Incremental) Fixed + Variable + Lease Costs +ST PPA	(Incremental) Capital + Renewable + VVO Program Costs	Contract (Revenue)/Cost	*Less:* Market Revenue	GRAND TOTAL, Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000
2019	678,067	357,242	23,245	29,683	192,979	0	43,454	745,681	578,988
2020	653,672	368,007	23,946	35,392	205,148	8,072	44,472	845,744	492,965
2021	642,024	361,265	23,624	40,613	205,369	8,139	44,899	838,895	487,040
2022	670,720	372,607	24,860	50,293	211,185	51,601	39,406	898,201	522,472
2023	697,906	379,634	24,801	60,088	240,018	71,199	36,237	973,014	536,870
2024	727,080	395,033	25,950	65,836	243,794	71,352	34,661	1,019,783	543,923
2025	750,837	400,621	26,075	56,857	249,529	97,075	34,270	1,036,948	578,314
2026	773,155	312,214	18,314	51,198	251,766	97,473	30,394	966,162	568,351
2027	802,988	315,715	17,646	54,626	254,035	112,327	28,154	1,001,678	583,813
2028	1,004,061	220,226	64,702	55,732	251,081	161,058	16,686	1,114,439	659,106
2029	1,011,147	216,301	94,448	59,888	261,828	450,781	9,422	1,212,478	891,335
2030	1,033,175	214,244	90,727	60,669	270,654	506,075	(1,100)	1,252,595	921,849
2031	1,050,471	227,694	115,986	64,482	274,662	550,232	(532)	1,320,052	962,943
2032	1,081,557	226,650	110,057	65,208	285,926	595,530	(1,460)	1,425,342	938,127
2033	1,105,223	232,010	113,981	69,219	293,065	641,122	(9,153)	1,486,472	958,994
2034	1,136,325	280,776	133,239	71,341	303,087	745,532	(11,466)	1,583,642	1,075,191
2035	1,181,663	250,628	147,955	75,291	276,708	790,991	(23,310)	1,385,221	1,314,706
2036	1,190,603	241,110	147,190	76,377	277,405	826,937	(22,291)	1,371,663	1,365,670
2037	1,226,123	374,705	195,025	81,120	315,142	960,734	(22,629)	1,674,411	1,455,808
2038	1,270,871	294,319	176,966	83,242	266,903	992,246	(26,369)	1,189,538	1,868,641
2039	1,305,270	380,022	216,433	66,290	124,870	805,396	(30,265)	1,376,187	1,491,829
2040	1,330,720	356,647	193,715	62,535	130,054	812,925	(42,017)	1,342,900	1,501,680
2041	1,350,531	348,372	210,300	56,414	131,304	817,323	(45,067)	1,339,429	1,529,748
2042	1,388,191	339,385	200,978	47,377	135,143	810,232	(46,179)	1,340,314	1,534,814
2043	1,411,141	324,020	204,744	42,639	138,763	802,889	(46,790)	1,331,818	1,545,588
2044	1,466,439	333,308	207,878	37,592	144,541	807,934	(48,533)	1,378,895	1,570,265
2045	1,495,103	309,528	210,210	33,678	147,979	798,993	(49,290)	1,364,537	1,581,664
2046	1,541,599	305,663	211,264	31,626	153,507	812,048	(48,200)	1,379,310	1,628,196
2047	1,584,176	309,178	224,921	29,140	160,126	816,625	(41,360)	1,422,457	1,660,349
2048	1,606,514	312,413	227,808	26,003	166,485	779,349	(42,456)	1,439,505	1,636,611

Indiana & Michigan POWER COMPANY
INTEGRATED RESOURCE PLAN
RP1 retires (12/31/2028) & RP2 lease extension + RP 2 FGD (12/31/2028) + RP2 Retirement (12/31/2048) CASE 8 Base Band Commodity Pricing

Resource (Capacity) Additions

Year	(10) (Current and Planned) Supply-Side + Purchased Unforced Capacity (UCAP) Ann MW	(11) Cum MW	(12) (Increm) EE+ VVO + DR + Battery Ann MW	(13) Cum MW	(14) Distributed Solar Ann MW	(15) Cum MW	(16) Generic Wind Ann MW	(17) Cum MW	(18) Utility Solar Ann MW	(19) Cum MW
2019	4,417	4,417	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2020	46	4,463	18.6	18.6	0.0	0.0	0.0	0.0	0.0	0.0
2021	11	4,474	17.4	36.1	0.0	0.0	0.0	0.0	0.0	0.0
2022	29	4,503	23.7	59.7	10.4	10.4	36.9	36.9	0.0	0.0
2023	411	4,914	9.0	68.7	2.1	12.4	18.5	55.4	0.0	0.0
2024	0	4,914	7.5	76.2	2.5	14.9	0.0	55.4	0.0	0.0
2025	(1,082)	3,832	30.5	106.7	0.8	15.7	0.0	55.4	76.3	76.3
2026	0	3,832	9.5	116.2	0.8	16.6	0.0	55.4	0.0	76.3
2027	(100)	3,732	8.0	124.2	0.8	17.4	0.0	55.4	76.3	152.6
2028	(44)	3,688	24.5	148.7	1.2	18.6	18.5	73.8	76.3	228.9
2029	(40)	3,648	(9.8)	138.9	1.7	20.3	18.5	92.3	76.3	305.1
2030	0	3,648	10.1	149.0	1.7	21.9	0.0	92.3	152.6	457.7
2031	0	3,648	(0.3)	148.7	1.7	23.6	18.5	110.7	76.3	534.0
2032	(13)	3,635	1.2	149.9	1.7	25.3	18.5	129.2	76.3	610.3
2033	0	3,635	0.6	150.4	2.5	27.7	18.5	147.6	76.3	686.6
2034	(582)	3,053	17.1	167.6	2.1	29.8	18.5	166.1	76.3	762.8
2035	(50)	3,003	13.1	180.7	1.7	31.5	18.5	184.5	76.3	839.1
2036	(7)	2,996	9.4	190.0	1.7	33.1	18.5	203.0	25.4	864.5
2037	(57)	2,939	(21.9)	168.1	1.7	34.8	18.5	221.4	0.0	864.5
2038	(50)	2,889	40.0	208.2	1.7	36.4	18.5	239.9	0.0	864.5
2039	135	3,024	8.1	216.3	2.1	38.5	18.5	258.3	0.0	864.5
2040	(106)	2,918	4.1	220.4	1.7	40.2	0.0	258.3	0.0	864.5
2041	(50)	2,868	22.6	242.9	2.1	42.2	0.0	258.3	0.0	864.5
2042	0	2,868	9.8	252.8	2.1	44.3	0.0	258.3	0.0	864.5
2043	0	2,868	9.2	262.0	2.1	46.4	0.0	258.3	0.0	864.5
2044	0	2,868	20.6	282.6	2.5	48.9	0.0	258.3	0.0	864.5
2045	0	2,868	11.9	294.5	2.5	51.3	0.0	258.3	0.0	864.5
2046	0	2,868	20.5	315.0	2.5	53.8	0.0	258.3	0.0	864.5
2047	0	2,868	18.5	333.5	2.9	56.7	0.0	258.3	0.0	864.5
2048	0	2,868	(19.3)	314.2	2.9	59.6	0.0	258.3	0.0	864.5

Energy & Capacity Positions / Carbon Output

Year	(20) Thermal Generation + Hydro GWh	(21) (Current) Purchased Energy Including OVEC GWh	(22) (New) Generic Wind + Utility Solar GWh	(23)=(20)+(21)+(22) = Market Sales GWh	(24) Load (Net of Embedded EE) GWh	(25) Less: (Increm) Energy Efficiency+ VVO+Dist Solar GWh	(26)=(24)-(25) = Net Load Requirements GWh	(27)=(23)-(26) ENERGY Surplus GWh	(28) Capacity MW	(29) Peak + Reserves MW	(30)=(28)-(29) CAPACITY Surplus MW	(31) Reserve Margin %	(32) Existing Units CO2 Emissions tons	(33) Total System CO2 tons	Year
2019	25,842	2,709	0	28,552	23,943	0	23,943	4,609	4,417	4,339	78	10.8	11,833,150	11,833,150	2019
2020	28,949	2,666	0	31,615	22,817	76	22,741	8,874	4,482	4,059	423	20.2	12,189,745	12,189,745	2020
2021	28,334	2,686	0	31,020	22,233	146	22,086	8,934	4,510	4,078	432	20.4	12,005,610	12,005,610	2021
2022	28,123	2,878	992	31,994	22,367	242	22,125	9,869	4,610	4,104	506	22.3	12,436,234	12,448,286	2022
2023	28,845	2,941	1,524	33,310	22,332	283	22,049	11,261	5,050	4,088	963	34.5	12,141,770	12,153,406	2023
2024	28,916	2,960	1,533	33,409	22,270	319	21,951	11,459	5,060	4,090	971	34.7	12,324,033	12,336,057	2024
2025	28,025	2,964	1,846	32,835	22,277	368	21,909	10,926	4,086	4,082	4	9.0	12,311,512	12,333,725	2025
2026	25,581	2,958	1,846	30,386	22,270	412	21,858	8,528	4,096	4,082	14	9.3	8,737,966	8,758,956	2026
2027	25,132	2,978	2,168	30,279	22,257	449	21,807	8,471	4,082	4,081	0	8.9	8,401,290	8,422,612	2027
2028	20,971	2,827	3,036	26,834	22,304	472	21,832	5,002	4,158	4,104	54	10.3	4,750,776	4,787,007	2028
2029	22,256	2,587	3,877	28,720	22,375	438	21,937	6,782	4,205	4,110	94	11.4	5,041,394	5,074,112	2029
2030	21,841	2,412	4,521	28,774	22,395	484	21,910	6,864	4,369	4,119	250	15.5	4,728,698	4,759,967	2030
2031	21,965	2,391	5,375	29,732	22,432	489	21,943	7,789	4,465	4,130	335	17.7	5,681,834	5,709,061	2031
2032	22,606	2,409	6,255	31,270	22,482	498	21,984	9,287	4,550	4,154	396	19.2	5,298,850	5,327,298	2032
2033	22,441	2,087	7,084	31,612	22,543	511	22,032	9,580	4,647	4,157	490	21.7	5,314,096	5,341,866	2033
2034	22,611	2,046	7,938	32,595	22,612	529	22,083	10,512	4,179	4,179	0	8.9	5,554,329	6,170,889	2034
2035	16,804	1,406	8,792	27,002	22,676	523	22,153	4,849	4,239	4,193	46	10.1	5,978,591	6,584,735	2035
2036	15,643	1,376	9,471	26,490	22,727	505	22,222	4,268	4,287	4,217	69	10.7	5,781,535	6,348,137	2036
2037	19,886	1,372	9,964	31,222	22,774	483	22,291	8,931	4,228	4,217	11	9.1	6,678,834	8,261,470	2037
2038	9,515	1,380	10,496	21,391	22,831	473	22,358	(967)	4,238	4,231	7	9.1	5,850,793	7,416,778	2038
2039	11,682	1,380	11,028	24,090	22,895	457	22,438	1,651	4,402	4,245	156	12.9	6,667,494	8,732,402	2039
2040	10,538	1,147	11,081	22,766	22,945	429	22,517	249	4,301	4,276	26	9.5	5,494,774	7,471,566	2040
2041	10,288	751	11,028	22,067	22,987	472	22,515	(448)	4,276	4,276	0	8.9	5,585,075	7,281,442	2041
2042	9,662	752	11,028	21,442	23,030	467	22,563	(1,121)	4,288	4,288	0	8.9	5,136,883	6,763,738	2042
2043	9,166	753	11,028	20,947	23,079	486	22,594	(1,647)	4,299	4,299	0	8.9	5,199,314	6,622,802	2043
2044	9,087	754	11,080	20,921	23,125	535	22,590	(1,670)	4,322	4,322	0	8.9	5,098,424	6,527,870	2044
2045	8,447	754	11,028	20,230	23,177	577	22,600	(2,370)	4,337	4,329	8	9.1	5,152,910	6,330,807	2045
2046	8,151	718	11,028	19,897	23,238	610	22,627	(2,730)	4,360	4,341	19	9.3	5,048,171	6,156,567	2046
2047	8,195	603	11,028	19,826	23,296	637	22,659	(2,833)	4,381	4,353	28	9.6	5,283,329	6,322,868	2047
2048	8,065	604	11,078	19,747	23,081	556	22,525	(2,777)	4,365	4,365	0	8.9	5,183,413	6,210,569	2048

Indiana & Michigan POWER COMPANY
INTEGRATED RESOURCE PLAN

RP1 retires (12/31/2028) & RP2 no lease extension (12/31/2022) CASE 5A
No Carbon Commodity Pricing

	Utility Costs (Nominal$000)								
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(1)thru(7)-(8)
	Load Cost	Fuel Costs	Emission Costs	Existing System FOM + OGC	(Incremental) Fixed + Variable + Lease Costs +ST PPA	(Incremental) Capital + Renewable + VVO Program Costs	Contract (Revenue)/Cost	*Less:* Market Revenue	GRAND TOTAL, Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000
2019	679,402	366,226	24,328	29,683	193,428	0	35,490	760,157	568,400
2020	653,133	368,427	24,136	35,392	205,081	8,072	36,340	844,154	486,427
2021	641,562	362,912	23,974	40,613	205,432	8,139	36,539	839,232	479,940
2022	673,278	373,218	24,660	50,293	213,634	66,349	30,602	910,791	521,242
2023	696,896	245,427	13,611	37,520	93,204	101,929	27,820	817,560	398,846
2024	726,278	248,047	13,640	49,700	96,650	101,420	26,283	854,564	407,454
2025	749,022	253,895	14,010	41,771	96,405	125,638	25,864	867,310	439,295
2026	771,429	235,904	13,770	44,934	104,471	141,018	21,888	914,487	418,927
2027	801,718	246,566	13,890	45,395	109,804	155,872	19,618	961,264	431,598
2028	816,693	361,252	14,202	50,938	133,512	272,678	20,939	1,114,003	556,210
2029	839,834	224,824	0	38,228	137,445	279,551	9,316	988,084	541,114
2030	865,852	231,263	0	38,228	143,166	298,703	(3,400)	1,027,721	546,092
2031	896,560	226,105	0	38,228	145,457	311,118	(5,001)	1,039,832	572,636
2032	932,061	241,571	0	38,228	158,439	329,383	(7,114)	1,139,240	553,329
2033	972,384	246,232	0	38,228	166,800	347,308	(10,022)	1,194,123	566,807
2034	1,005,774	376,659	0	38,228	185,270	479,128	(12,799)	1,368,426	703,835
2035	1,045,753	342,764	0	38,228	155,857	512,065	(28,226)	1,159,071	907,371
2036	1,059,905	340,640	0	38,228	156,413	541,800	(28,337)	1,154,751	953,899
2037	1,098,698	564,965	0	38,228	194,656	724,121	(29,545)	1,522,020	1,069,103
2038	1,149,207	523,569	0	38,228	150,046	755,589	(34,237)	1,150,989	1,431,413
2039	1,162,572	517,627	0	33,438	154,050	780,862	(36,993)	1,158,822	1,452,733
2040	1,188,564	531,126	0	29,682	164,590	826,129	(47,096)	1,211,934	1,481,061
2041	1,208,450	507,246	0	23,561	164,789	860,025	(40,529)	1,199,583	1,523,959
2042	1,227,456	496,070	0	14,524	169,000	889,244	(40,975)	1,212,837	1,542,483
2043	1,258,698	483,404	0	12,155	169,592	927,178	(41,925)	1,241,295	1,567,808
2044	1,295,892	493,419	0	9,631	175,238	955,552	(43,040)	1,291,732	1,594,961
2045	1,333,912	489,628	0	7,674	179,512	952,445	(44,160)	1,300,705	1,618,305
2046	1,378,248	476,676	0	5,623	184,303	955,828	(43,283)	1,304,800	1,652,595
2047	1,417,026	481,640	0	3,136	190,541	962,064	(37,163)	1,332,927	1,684,316
2048	1,433,367	466,178	0	0	200,484	923,067	(38,045)	1,322,054	1,662,997

Indiana & Michigan POWER COMPANY
INTEGRATED RESOURCE PLAN
RP1 retires (12/31/2028) & RP2 no lease extension (12/31/2022) CASE 5A No Carbon Commodity Pricing

	Resource (Capacity) Additions									
	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
	(Current and Planned) Supply-Side + Purchased Unforced Capacity (UCAP)		(Increm) EE+ VVO + DR + Battery		Distributed Solar		Generic Wind		Utility Solar	
	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW
2019	4,417	4,417	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2020	46	4,463	18.6	18.6	0.0	0.0	0.0	0.0	0.0	0.0
2021	11	4,474	17.4	36.1	0.0	0.0	0.0	0.0	0.0	0.0
2022	29	4,503	24.1	60.2	10.4	10.4	36.9	36.9	76.3	76.3
2023	(699)	3,804	11.6	71.8	2.1	12.4	18.5	55.4	76.3	152.6
2024	0	3,804	8.9	80.7	2.5	14.9	0.0	55.4	0.0	152.6
2025	(132)	3,672	29.9	110.6	0.8	15.7	0.0	55.4	76.3	228.9
2026	0	3,672	8.9	119.4	0.8	16.6	0.0	55.4	76.3	305.1
2027	0	3,672	7.4	126.9	0.8	17.4	0.0	55.4	76.3	381.4
2028	(273)	3,399	46.6	173.4	1.2	18.6	0.0	55.4	76.3	457.7
2029	(57)	3,342	(8.2)	165.2	1.7	20.3	0.0	55.4	76.3	534.0
2030	(100)	3,242	24.2	189.4	1.7	21.9	0.0	55.4	76.3	610.3
2031	(50)	3,192	10.0	199.4	1.7	23.6	0.0	55.4	76.3	686.6
2032	(13)	3,179	15.2	214.6	1.7	25.3	0.0	55.4	76.3	762.8
2033	0	3,179	23.4	238.0	2.5	27.7	0.0	55.4	76.3	839.1
2034	(197)	2,982	14.3	252.3	2.1	29.8	18.5	73.8	25.4	864.5
2035	(50)	2,932	20.5	272.8	1.7	31.5	18.5	92.3	0.0	864.5
2036	(7)	2,925	11.1	283.9	1.7	33.1	18.5	110.7	0.0	864.5
2037	28	2,953	(24.9)	259.1	1.7	34.8	18.5	129.2	0.0	864.5
2038	0	2,953	40.0	299.1	1.7	36.4	18.5	147.6	0.0	864.5
2039	0	2,953	(1.8)	297.3	2.1	38.5	18.5	166.1	0.0	864.5
2040	(56)	2,897	5.3	302.6	1.7	40.2	18.5	184.5	0.0	864.5
2041	(50)	2,847	16.6	319.2	2.1	42.2	18.5	203.0	0.0	864.5
2042	0	2,847	17.9	337.1	2.1	44.3	18.5	221.4	0.0	864.5
2043	(50)	2,797	14.3	351.4	2.1	46.4	18.5	239.9	0.0	864.5
2044	0	2,797	2.4	353.8	2.5	48.9	18.5	258.3	0.0	864.5
2045	0	2,797	4.1	357.9	2.5	51.3	0.0	258.3	0.0	864.5
2046	0	2,797	15.0	372.9	2.5	53.8	0.0	258.3	0.0	864.5
2047	0	2,797	4.5	377.4	2.9	56.7	0.0	258.3	0.0	864.5
2048	50	2,847	(42.2)	335.2	2.9	59.6	0.0	258.3	0.0	864.5

	Energy & Capacity Positions												Carbon Output		
	(20)	(21)	(22)	(23)=(20)+(21)+(22)	(24)	(25)	(26)=(24)-(25)	(27)=(23)-(26)	(28)	(29)	(30)=(28)-(29)	(31)	(32)	(33)	
	Thermal Generation + Hydro	(Current) Purchased Energy Including OVEC	(New) Generic Wind + Utility Solar	= Market Sales	Load (Net of Embedded EE)	*Less:* (Increm) Energy Efficiency+ VVO+Dist Solar	= Net Load Requirements	ENERGY Surplus	Capacity	Peak + Reserves	CAPACITY Surplus	Reserve Margin	Existing Units CO2 Emissions	Total System CO2	
	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	%	tons	tons	
2019	26,284	2,385	0	28,669	23,943	0	23,943	4,726	4,417	4,339	78	10.8	12,254,837	12,254,837	2019
2020	28,918	2,341	0	31,260	22,817	58	22,759	8,501	4,482	4,059	423	20.2	12,219,263	12,219,263	2020
2021	28,416	2,361	0	30,778	22,233	112	22,121	8,657	4,510	4,078	432	20.4	12,109,829	12,109,829	2021
2022	28,171	2,557	1,314	32,042	22,367	197	22,170	9,872	4,687	4,104	583	24.3	12,515,281	12,527,650	2022
2023	23,677	2,615	2,168	28,461	22,332	240	22,092	6,369	4,096	4,088	9	9.1	7,071,093	7,082,666	2023
2024	23,557	2,634	2,178	28,369	22,270	279	21,991	6,378	4,108	4,090	18	9.3	6,906,841	6,918,769	2024
2025	22,778	2,638	2,491	27,906	22,277	312	21,965	5,941	4,083	4,082	0	8.9	7,040,059	7,062,046	2025
2026	22,752	2,633	2,813	28,198	22,270	341	21,928	6,269	4,168	4,082	87	11.2	5,951,807	5,972,670	2026
2027	22,635	2,652	3,135	28,422	22,257	366	21,890	6,531	4,253	4,081	172	13.4	5,954,235	5,975,238	2027
2028	25,796	2,653	3,469	31,918	22,304	414	21,891	10,027	4,104	4,104	0	8.9	5,932,346	8,086,791	2028
2029	21,872	2,443	3,779	28,093	22,375	353	22,022	6,071	4,117	4,110	6	9.0	926,566	3,072,966	2029
2030	21,715	2,282	4,101	28,098	22,395	387	22,008	6,090	4,119	4,119	0	8.9	921,865	3,050,915	2030
2031	20,728	2,287	4,423	27,438	22,432	389	22,044	5,395	4,157	4,130	27	9.6	926,175	2,979,821	2031
2032	21,893	2,299	4,760	28,952	22,482	394	22,088	6,864	4,237	4,154	83	11.1	935,647	3,066,823	2032
2033	21,683	2,300	5,067	29,050	22,543	403	22,140	6,910	4,339	4,157	182	13.6	938,974	3,055,708	2033
2034	23,932	2,264	5,707	31,903	22,612	411	22,201	9,702	4,202	4,179	23	9.5	930,947	4,506,830	2034
2035	17,741	1,612	6,239	25,591	22,676	440	22,236	3,356	4,193	4,193	0	8.9	927,148	4,485,398	2035
2036	16,758	1,619	6,796	25,173	22,727	436	22,291	2,882	4,217	4,217	0	8.9	943,042	4,465,733	2036
2037	22,840	1,604	7,303	31,747	22,774	416	22,358	9,389	4,241	4,217	23	9.5	943,148	6,445,150	2037
2038	13,588	1,598	7,835	23,021	22,831	406	22,425	596	4,301	4,231	70	10.7	935,009	6,587,818	2038
2039	12,988	1,595	8,368	22,951	22,895	360	22,535	416	4,319	4,245	74	10.8	931,292	6,299,471	2039
2040	13,013	1,426	8,940	23,379	22,945	337	22,608	772	4,289	4,276	13	9.2	742,874	6,113,435	2040
2041	11,877	754	9,432	22,063	22,987	355	22,632	(570)	4,276	4,276	0	8.9	0	4,901,082	2041
2042	11,148	754	9,964	21,867	23,030	374	22,656	(790)	4,314	4,288	27	9.5	0	4,604,984	2042
2043	10,508	755	10,496	21,759	23,079	431	22,648	(889)	4,299	4,299	0	8.9	0	4,315,647	2043
2044	10,257	756	11,080	22,092	23,125	430	22,695	(603)	4,323	4,322	0	8.9	0	4,190,949	2044
2045	9,781	756	11,028	21,565	23,177	448	22,729	(1,164)	4,329	4,329	0	8.9	0	3,982,029	2045
2046	9,169	720	11,028	20,918	23,238	496	22,742	(1,824)	4,347	4,341	6	9.0	0	3,770,400	2046
2047	9,003	605	11,028	20,637	23,296	522	22,774	(2,137)	4,354	4,353	1	8.9	0	3,718,702	2047
2048	8,446	607	11,078	20,130	23,081	470	22,611	(2,481)	4,365	4,365	0	8.9	0	3,491,507	2048

Indiana & Michigan POWER COMPANY
INTEGRATED RESOURCE PLAN

RP1 FGD (12/31/2025) RP1 Retires (12/31/2044) & RP2 no lease extension (12/31/2022) CASE 6a No Carbon Commodity Pricing

	Utility Costs (Nominal$000)								
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(1)thru(7)-(8)
	Load Cost	Fuel Costs	Emission Costs	Existing System FOM + OGC	(Incremental) Fixed + Variable + Lease Costs +ST PPA	(Incremental) Capital + Renewable + VVO Program Costs	Contract (Revenue)/Cost	*Less:* Market Revenue	GRAND TOTAL, Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000
2019	679,402	366,226	24,328	29,683	193,428	0	35,557	760,157	568,467
2020	653,133	368,427	24,136	35,392	205,081	8,072	36,409	844,154	486,496
2021	641,562	362,912	23,974	40,613	205,432	8,139	36,605	839,232	480,007
2022	673,278	373,218	24,660	50,293	211,203	52,582	30,673	900,491	515,416
2023	696,896	245,427	13,611	37,520	91,627	95,152	27,894	808,263	399,863
2024	726,278	248,047	13,640	49,700	94,992	86,319	26,363	843,551	401,787
2025	749,022	234,201	12,373	41,771	92,770	96,281	25,947	827,477	424,889
2026	771,429	269,680	44,244	44,934	102,466	342,919	21,972	931,669	665,975
2027	801,718	278,884	44,341	45,395	106,235	382,887	19,706	975,800	703,366
2028	816,693	268,036	41,515	50,938	108,367	400,145	21,026	961,108	745,613
2029	839,834	273,259	39,236	50,616	118,129	413,047	9,403	1,013,392	730,133
2030	865,852	278,546	39,057	56,936	125,387	434,895	(3,309)	1,054,559	742,806
2031	896,560	281,290	40,942	58,034	128,305	449,523	(4,904)	1,077,042	772,707
2032	932,061	292,366	41,016	62,426	140,482	474,996	(7,010)	1,169,384	766,953
2033	972,384	302,176	42,466	64,060	148,738	492,920	(9,920)	1,231,482	781,342
2034	1,005,774	370,771	45,191	67,807	160,517	557,844	(12,691)	1,312,085	883,129
2035	1,045,753	356,438	51,228	69,734	133,458	605,808	(28,113)	1,141,334	1,092,971
2036	1,059,905	325,431	44,670	55,879	132,294	381,624	(28,223)	1,100,165	871,415
2037	1,098,698	557,682	47,374	55,879	170,674	564,079	(29,432)	1,478,713	986,241
2038	1,149,207	510,360	48,243	55,879	125,084	595,592	(34,115)	1,102,159	1,348,090
2039	1,162,572	521,249	51,408	51,088	129,541	625,030	(36,874)	1,130,462	1,373,553
2040	1,188,564	524,393	50,367	47,333	139,123	667,137	(46,977)	1,173,558	1,396,382
2041	1,208,450	503,490	48,681	41,212	139,602	701,757	(40,403)	1,168,598	1,434,191
2042	1,227,456	480,481	45,001	32,175	143,236	728,745	(40,846)	1,166,959	1,449,290
2043	1,258,698	496,864	50,144	29,806	145,308	763,400	(41,793)	1,230,634	1,471,792
2044	1,295,892	519,438	54,083	27,282	151,638	798,025	(42,903)	1,302,744	1,500,711
2045	1,333,912	489,628	0	25,325	179,073	1,014,744	(44,024)	1,302,856	1,695,802
2046	1,378,248	476,676	0	23,274	184,303	1,013,047	(43,142)	1,305,448	1,726,958
2047	1,417,026	481,640	0	20,787	190,541	1,019,447	(37,020)	1,333,323	1,759,098
2048	1,433,367	466,178	0	17,651	200,484	980,054	(37,895)	1,322,165	1,737,673

Indiana & Michigan POWER COMPANY
INTEGRATED RESOURCE PLAN
RP1 FGD (12/31/2025) RP1 Retires (12/31/2044) & RP2 no lease extension (12/31/2022) CASE 6a No Carbon Commodity Pricing

	Resource (Capacity) Additions										Energy & Capacity Positions												Carbon Output		
	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)=(20)+(21)+(22)	(24)	(25)	(26)=(24)-(25)	(27)=(23)-(26)	(28)	(29)	(30)=(28)-(29)	(31)	(32)	(33)	
	(Current and Planned) Supply-Side + Purchased Unforced Capacity (UCAP)		(Increm) EE+ VVO + DR + Battery		Distributed Solar		Generic Wind		Utility Solar		Thermal Generation + Hydro	(Current) Purchased Energy Including OVEC	(New) Generic Wind + Utility Solar	= Market Sales	Load (Net of Embedded EE)	*Less:* (Increm) Energy Efficiency+ VVO+Dist Solar	= Net Load Requirements	ENERGY Surplus	Capacity	Peak + Reserves	CAPACITY Surplus	Reserve Margin	Existing Units CO2 Emissions	Total System CO2	
	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	%	tons	tons	
2019	4,417	4,417	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	26,284	2,383	0	28,667	23,943	0	23,943	4,724	4,417	4,339	78	10.8	12,254,837	12,254,837	2019
2020	46	4,463	18.6	18.6	0.0	0.0	0.0	0.0	0.0	0.0	28,918	2,339	0	31,257	22,817	76	22,741	8,516	4,482	4,059	423	20.2	12,219,263	12,219,263	2020
2021	11	4,474	17.4	36.1	0.0	0.0	0.0	0.0	0.0	0.0	28,416	2,359	0	30,775	22,233	146	22,086	8,689	4,510	4,078	432	20.4	12,109,829	12,109,829	2021
2022	29	4,503	25.3	61.3	10.4	10.4	36.9	36.9	0.0	0.0	28,171	2,554	992	31,718	22,367	251	22,116	9,602	4,612	4,104	508	22.3	12,515,268	12,527,637	2022
2023	(649)	3,854	28.2	89.5	2.1	12.4	18.5	55.4	76.3	76.3	23,677	2,613	1,846	28,136	22,332	345	21,987	6,149	4,088	4,088	0	8.9	7,071,093	7,082,666	2023
2024	0	3,854	0.0	89.6	2.5	14.9	0.0	55.4	0.0	76.3	23,557	2,631	1,856	28,044	22,270	351	21,918	6,126	4,090	4,090	0	8.9	6,906,841	6,918,769	2024
2025	(32)	3,822	29.3	118.9	0.8	15.7	0.0	55.4	0.0	76.3	22,242	2,636	1,846	26,724	22,277	393	21,883	4,841	4,088	4,082	6	9.0	6,326,106	6,348,093	2025
2026	(83)	3,739	8.3	127.2	0.8	16.6	0.0	55.4	76.3	152.6	24,128	2,631	2,168	28,927	22,270	431	21,838	7,089	4,091	4,082	9	9.1	7,042,326	7,063,188	2026
2027	(100)	3,639	13.7	140.9	0.8	17.4	0.0	55.4	76.3	228.9	23,890	2,649	2,491	29,030	22,257	490	21,767	7,263	4,081	4,081	0	8.9	6,942,812	6,963,816	2027
2028	6	3,645	15.9	156.8	1.2	18.6	0.0	55.4	76.3	305.1	22,617	2,651	2,824	28,092	22,304	477	21,827	6,264	4,181	4,104	77	10.9	6,429,750	6,460,121	2028
2029	(6)	3,639	(11.4)	145.4	1.7	20.3	0.0	55.4	76.3	381.4	23,090	2,440	3,135	28,665	22,375	434	21,941	6,724	4,241	4,110	131	12.3	6,024,784	6,055,267	2029
2030	0	3,639	9.8	155.2	1.7	21.9	0.0	55.4	101.7	483.1	22,839	2,280	3,564	28,684	22,395	479	21,915	6,768	4,355	4,119	236	15.1	5,890,032	5,921,174	2030
2031	0	3,639	(0.3)	154.9	1.7	23.6	0.0	55.4	76.3	559.4	22,139	2,285	3,886	28,310	22,432	484	21,949	6,361	4,432	4,130	302	16.8	6,025,080	6,055,871	2031
2032	(13)	3,626	15.6	170.5	1.7	25.3	0.0	55.4	76.3	635.7	23,059	2,296	4,222	29,578	22,482	493	21,988	7,589	4,513	4,154	359	18.3	5,937,307	5,970,359	2032
2033	0	3,626	23.8	194.3	2.5	27.7	0.0	55.4	76.3	712.0	22,966	2,297	4,530	29,794	22,543	541	22,002	7,792	4,615	4,157	458	20.9	6,009,728	6,045,544	2033
2034	(532)	3,094	17.6	211.8	2.1	29.8	0.0	55.4	76.3	788.3	23,421	2,261	4,852	30,534	22,612	562	22,050	8,485	4,179	4,179	0	8.9	6,214,329	6,954,266	2034
2035	(100)	2,994	17.5	229.3	1.7	31.5	18.5	73.8	76.3	864.5	17,817	1,609	5,707	25,133	22,676	578	22,098	3,035	4,193	4,193	0	8.9	6,792,257	7,530,531	2035
2036	(7)	2,987	11.0	240.3	1.7	33.1	18.5	92.3	0.0	864.5	16,044	1,617	6,261	23,922	22,727	569	22,159	1,763	4,217	4,217	0	8.9	5,950,638	6,679,979	2036
2037	27	3,014	(24.6)	215.7	1.7	34.8	18.5	110.7	0.0	864.5	22,424	1,602	6,771	30,797	22,774	539	22,235	8,561	4,240	4,217	22	9.5	6,143,113	8,912,494	2037
2038	0	3,014	33.0	248.8	1.7	36.4	18.5	129.2	0.0	864.5	13,042	1,595	7,303	21,941	22,831	523	22,308	(367)	4,293	4,231	62	10.5	6,119,801	8,943,810	2038
2039	0	3,014	4.0	252.7	2.1	38.5	18.5	147.6	0.0	864.5	12,921	1,593	7,835	22,349	22,895	485	22,410	(60)	4,317	4,245	72	10.7	6,340,715	9,037,278	2039
2040	(55)	2,959	4.3	257.1	1.7	40.2	18.5	166.1	0.0	864.5	12,716	1,423	8,405	22,545	22,945	459	22,487	58	4,287	4,276	11	9.2	5,931,940	8,633,677	2040
2041	(50)	2,909	18.6	275.6	2.1	42.2	18.5	184.5	0.0	864.5	11,785	751	8,900	21,436	22,987	488	22,499	(1,063)	4,276	4,276	0	8.9	4,910,396	7,373,384	2041
2042	0	2,909	12.9	288.5	2.1	44.3	18.5	203.0	0.0	864.5	10,895	752	9,432	21,079	23,030	494	22,536	(1,457)	4,309	4,288	22	9.4	4,443,180	6,752,046	2042
2043	(50)	2,859	19.5	308.0	2.1	46.4	18.5	221.4	0.0	864.5	10,938	753	9,964	21,655	23,079	526	22,553	(898)	4,299	4,299	0	8.9	4,846,895	7,021,281	2043
2044	0	2,859	20.6	328.6	2.5	48.9	18.5	239.9	0.0	864.5	11,070	754	10,545	22,368	23,125	563	22,562	(194)	4,341	4,322	19	9.3	5,117,458	7,238,309	2044
2045	(62)	2,797	29.1	357.7	2.5	51.3	18.5	258.3	0.0	864.5	9,781	754	11,028	21,563	23,177	629	22,547	(984)	4,329	4,329	0	8.9	0	3,523,392	2045
2046	0	2,797	17.7	375.4	2.5	53.8	0.0	258.3	0.0	864.5	9,169	718	11,028	20,915	23,238	652	22,586	(1,670)	4,349	4,341	8	9.1	0	3,300,606	2046
2047	0	2,797	3.5	378.9	2.9	56.7	0.0	258.3	0.0	864.5	9,003	603	11,028	20,634	23,296	675	22,621	(1,986)	4,355	4,353	2	8.9	0	3,240,209	2047
2048	50	2,847	(43.7)	335.2	2.9	59.6	0.0	258.3	0.0	864.5	8,446	604	11,078	20,128	23,081	556	22,525	(2,397)	4,365	4,365	0	8.9	0	3,036,585	2048

Indiana & Michigan POWER COMPANY
INTEGRATED RESOURCE PLAN

RP1 FGD (12/31/2028) & RP2 no lease extension (12/31/2022) CASE 7a No Carbon Commodity Pricing

	Utility Costs (Nominal$000)								
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(1)thru(7)-(8)
	Load Cost	Fuel Costs	Emission Costs	Existing System FOM + OGC	(Incremental) Fixed + Variable + Lease Costs +ST PPA	(Incremental) Capital + Renewable + VVO Program Costs	Contract (Revenue)/Cost	*Less:* Market Revenue	GRAND TOTAL, Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000
2019	679,402	364,680	24,194	29,683	193,358	0	35,687	757,369	569,635
2020	653,133	368,811	24,193	35,392	205,101	8,072	36,325	845,202	485,825
2021	641,562	363,181	23,997	40,613	205,444	8,139	36,526	840,332	479,132
2022	673,278	372,614	24,605	50,293	211,176	52,582	30,953	896,781	518,718
2023	696,896	245,728	13,638	37,520	91,636	95,152	27,782	809,182	399,169
2024	726,278	248,355	13,667	49,700	95,008	85,683	26,279	844,740	400,229
2025	749,022	254,078	14,032	41,771	93,433	96,281	25,749	846,484	427,882
2026	771,429	236,776	13,872	44,934	99,852	106,667	21,758	889,394	405,895
2027	801,718	246,696	13,880	45,395	103,779	121,334	19,561	934,307	418,056
2028	816,693	249,047	14,207	50,938	106,419	141,357	(1,406)	1,113,772	263,483
2029	839,834	389,625	67,970	50,616	122,326	401,831	(9,420)	1,340,692	522,089
2030	865,852	379,452	63,859	56,936	129,835	453,231	(20,378)	1,358,092	570,695
2031	896,560	400,701	69,966	58,034	133,481	468,054	(20,517)	1,386,570	619,709
2032	932,061	388,974	64,654	62,426	144,713	493,526	(22,227)	1,448,136	615,991
2033	972,384	412,607	68,963	64,060	153,443	511,451	(23,331)	1,508,601	650,975
2034	1,005,774	470,532	69,020	67,807	164,743	576,337	(25,717)	1,561,062	767,435
2035	1,045,753	458,960	75,604	69,734	137,797	624,389	(37,848)	1,365,053	1,009,337
2036	1,059,905	407,375	64,195	74,481	135,783	654,218	(37,612)	1,287,634	1,070,710
2037	1,098,698	674,447	74,692	76,004	175,519	836,673	(38,448)	1,707,659	1,189,925
2038	1,149,207	598,012	68,913	79,986	128,772	868,186	(42,738)	1,242,824	1,607,514
2039	1,162,572	637,741	78,873	59,441	134,425	625,267	(46,983)	1,314,926	1,336,410
2040	1,188,564	631,915	75,617	55,686	143,614	667,332	(55,879)	1,343,665	1,363,183
2041	1,208,450	640,621	80,690	49,564	145,285	701,952	(45,067)	1,372,003	1,409,492
2042	1,227,456	590,971	70,739	40,527	147,807	728,940	(46,179)	1,340,773	1,419,488
2043	1,258,698	640,905	83,772	38,158	151,276	763,494	(46,790)	1,447,639	1,441,874
2044	1,295,892	643,614	83,175	35,635	156,818	798,220	(48,533)	1,502,117	1,462,705
2045	1,333,912	489,628	0	33,678	179,073	1,014,938	(49,290)	1,303,638	1,698,300
2046	1,378,248	476,676	0	31,626	184,303	1,013,262	(48,200)	1,306,242	1,729,673
2047	1,417,026	481,640	0	29,140	190,541	1,019,706	(41,360)	1,334,139	1,762,553
2048	1,433,367	466,178	0	26,003	200,484	980,248	(42,456)	1,323,014	1,740,810

Indiana & Michigan POWER COMPANY
INTEGRATED RESOURCE PLAN
RP1 FGD (12/31/2028) & RP2 no lease extension (12/31/2022) CASE 7a No Carbon Commodity Pricing

	Resource (Capacity) Additions										Energy & Capacity Positions												Carbon Output		
	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)=(20)+(21)+(22)	(24)	(25)	(26)=(24)-(25)	(27)=(23)-(26)	(28)	(29)	(30)=(28)-(29)	(31)	(32)	(33)	
	(Current and Planned) Supply-Side + Purchased Unforced Capacity (UCAP)		(Increm) EE+ VVO + DR + Battery		Distributed Solar		Generic Wind		Utility Solar		Thermal Generation + Hydro	(Current) Purchased Energy Including OVEC	(New) Generic Wind + Utility Solar	= Market Sales	Load (Net of Embedded EE)	*Less:* (Increm) Energy Efficiency+ VVO+Dist Solar	= Net Load Requirements	ENERGY Surplus	Capacity	Peak + Reserves	CAPACITY Surplus	Reserve Margin	Existing Units CO2 Emissions	Total System CO2	
	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	%	tons	tons	
2019	4,417	4,417	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	26,221	2,383	0	28,604	23,943	0	23,943	4,661	4,417	4,339	78	10.8	12,188,418	12,188,418	2019
2020	46	4,463	18.6	18.6	0.0	0.0	0.0	0.0	0.0	0.0	28,937	2,339	0	31,276	22,817	76	22,741	8,535	4,482	4,059	423	20.2	12,244,217	12,244,217	2020
2021	11	4,474	17.4	36.1	0.0	0.0	0.0	0.0	0.0	0.0	28,427	2,360	0	30,787	22,233	146	22,086	8,700	4,510	4,078	432	20.4	12,121,702	12,121,702	2021
2022	29	4,503	25.3	61.3	10.4	10.4	36.9	36.9	0.0	0.0	28,148	2,552	992	31,692	22,367	251	22,116	9,575	4,612	4,104	508	22.3	12,486,568	12,498,937	2022
2023	(649)	3,854	28.2	89.5	2.1	12.4	18.5	55.4	76.3	76.3	23,684	2,614	1,846	28,144	22,332	345	21,987	6,157	4,088	4,088	0	8.9	7,084,428	7,096,000	2023
2024	0	3,854	(0.3)	89.2	2.5	14.9	0.0	55.4	0.0	76.3	23,570	2,632	1,856	28,058	22,270	349	21,921	6,138	4,090	4,090	0	8.9	6,919,992	6,931,921	2024
2025	(32)	3,822	28.9	118.1	0.8	15.7	0.0	55.4	0.0	76.3	22,760	2,638	1,846	27,244	22,277	389	21,888	5,356	4,087	4,082	5	9.0	7,050,475	7,072,461	2025
2026	(50)	3,772	8.5	126.6	0.8	16.6	0.0	55.4	50.9	127.1	22,758	2,632	2,061	27,451	22,270	428	21,842	5,609	4,098	4,082	16	9.3	5,992,754	6,013,617	2026
2027	(100)	3,672	6.8	133.4	0.8	17.4	0.0	55.4	76.3	203.4	22,683	2,650	2,383	27,716	22,257	459	21,797	5,919	4,082	4,081	0	8.9	5,949,031	5,970,034	2027
2028	7	3,679	23.1	156.5	1.2	18.6	0.0	55.4	76.3	279.7	21,852	2,686	2,716	27,254	22,304	475	21,829	5,424	4,189	4,104	85	11.1	5,983,967	6,014,338	2028
2029	(40)	3,639	(11.3)	145.2	1.7	20.3	0.0	55.4	76.3	356.0	26,900	2,468	3,027	32,395	22,375	432	21,942	10,453	4,216	4,110	105	11.7	9,790,692	9,821,174	2029
2030	0	3,639	9.7	154.9	1.7	21.9	0.0	55.4	127.1	483.1	26,069	2,304	3,564	31,937	22,395	478	21,917	10,020	4,354	4,119	236	15.1	9,072,991	9,104,133	2030
2031	0	3,639	(0.2)	154.7	1.7	23.6	0.0	55.4	76.3	559.4	25,820	2,301	3,886	32,008	22,432	483	21,950	10,058	4,432	4,130	302	16.8	9,660,068	9,690,859	2031
2032	(13)	3,626	15.7	170.4	1.7	25.3	0.0	55.4	76.3	635.7	26,005	2,315	4,222	32,542	22,482	493	21,989	10,552	4,513	4,154	359	18.3	8,841,191	8,874,244	2032
2033	0	3,626	23.8	194.2	2.5	27.7	0.0	55.4	76.3	712.0	26,175	2,309	4,530	33,014	22,543	541	22,003	11,012	4,615	4,157	458	20.9	9,187,212	9,223,028	2033
2034	(532)	3,094	17.8	212.0	2.1	29.8	0.0	55.4	76.3	788.3	26,240	2,273	4,852	33,366	22,612	563	22,049	11,316	4,179	4,179	0	8.9	9,014,808	9,754,744	2034
2035	(100)	2,994	17.3	229.3	1.7	31.5	18.5	73.8	76.3	864.5	20,656	1,617	5,707	27,979	22,676	578	22,098	5,881	4,193	4,193	0	8.9	9,593,598	10,331,873	2035
2036	(7)	2,987	11.0	240.3	1.7	33.1	18.5	92.3	0.0	864.5	18,273	1,626	6,261	26,159	22,727	569	22,159	4,001	4,217	4,217	0	8.9	8,150,138	8,879,480	2036
2037	28	3,015	(24.6)	215.7	1.7	34.8	18.5	110.7	0.0	864.5	25,459	1,607	6,771	33,838	22,774	539	22,236	11,602	4,241	4,217	23	9.5	9,149,687	11,919,068	2037
2038	0	3,015	33.0	248.8	1.7	36.4	18.5	129.2	0.0	864.5	15,299	1,603	7,303	24,206	22,831	523	22,308	1,898	4,294	4,231	63	10.5	8,351,627	11,175,637	2038
2039	0	3,015	4.0	252.8	2.1	38.5	18.5	147.6	0.0	864.5	15,855	1,598	7,835	25,288	22,895	485	22,410	2,878	4,318	4,245	73	10.7	9,238,170	11,934,733	2039
2040	(56)	2,959	4.3	257.1	1.7	40.2	18.5	166.1	0.0	864.5	15,355	1,424	8,405	25,184	22,945	459	22,487	2,697	4,287	4,276	11	9.2	8,534,990	11,236,727	2040
2041	(50)	2,909	18.5	275.7	2.1	42.2	18.5	184.5	0.0	864.5	15,054	751	8,900	24,705	22,987	488	22,499	2,206	4,276	4,276	0	8.9	8,140,920	10,603,909	2041
2042	0	2,909	12.9	288.5	2.1	44.3	18.5	203.0	0.0	864.5	13,466	752	9,432	23,650	23,030	495	22,536	1,114	4,309	4,288	22	9.4	6,985,773	9,294,639	2042
2043	(50)	2,859	19.2	307.8	2.1	46.4	18.5	221.4	0.0	864.5	14,226	753	9,964	24,943	23,079	525	22,554	2,388	4,299	4,299	0	8.9	8,098,982	10,273,368	2043
2044	0	2,859	20.8	328.6	2.5	48.9	18.5	239.9	0.0	864.5	13,860	754	10,545	25,158	23,125	563	22,562	2,597	4,341	4,322	19	9.3	7,871,713	9,992,564	2044
2045	(62)	2,797	29.1	357.7	2.5	51.3	18.5	258.3	0.0	864.5	9,781	754	11,028	21,563	23,177	629	22,547	(984)	4,329	4,329	0	8.9	0	3,523,392	2045
2046	0	2,797	17.7	375.4	2.5	53.8	0.0	258.3	0.0	864.5	9,169	718	11,028	20,915	23,238	652	22,586	(1,670)	4,349	4,341	8	9.1	0	3,300,606	2046
2047	0	2,797	3.5	378.9	2.9	56.7	0.0	258.3	0.0	864.5	9,003	603	11,028	20,634	23,296	675	22,621	(1,986)	4,355	4,353	2	8.9	0	3,240,209	2047
2048	50	2,847	(43.7)	335.2	2.9	59.6	0.0	258.3	0.0	864.5	8,446	604	11,078	20,128	23,081	556	22,525	(2,397)	4,365	4,365	0	8.9	0	3,036,585	2048

Indiana & Michigan POWER COMPANY
INTEGRATED RESOURCE PLAN

RP1 retires (12/31/2028) & RP2 lease extension + RP 2 FGD (12/31/2028) + RP2 Retirement (12/31/2048) CASE 8a No Carbon Commodity Pricing

	Utility Costs (Nominal$000)								
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(1)thru(7)-(8)
	Load Cost	Fuel Costs	Emission Costs	Existing System FOM + OGC	(Incremental) Fixed + Variable + Lease Costs +ST PPA	(Incremental) Capital + Renewable + VVO Program Costs	Contract (Revenue)/Cost	*Less:* Market Revenue	GRAND TOTAL, Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000
2019	679,402	357,242	23,245	29,683	192,979	0	35,687	745,681	572,557
2020	653,133	368,007	23,946	35,392	205,148	8,072	36,325	845,742	484,280
2021	641,562	361,265	23,624	40,613	205,369	8,139	36,526	838,893	478,207
2022	673,278	372,626	24,860	50,293	211,189	51,468	30,953	898,321	516,346
2023	696,896	379,630	24,801	60,088	240,018	71,199	27,782	972,909	527,505
2024	726,278	395,027	25,950	65,836	243,793	71,461	26,279	1,019,718	534,905
2025	749,022	400,605	26,075	56,857	246,538	87,133	25,749	1,028,964	563,015
2026	771,429	312,204	18,314	51,198	250,013	97,519	21,758	965,969	556,466
2027	801,718	315,691	17,646	54,626	253,507	112,373	19,560	1,001,494	573,628
2028	816,693	287,582	15,378	55,732	254,144	130,365	(1,406)	1,155,703	402,786
2029	839,834	367,674	62,553	59,888	267,071	392,683	(9,420)	1,297,675	682,608
2030	865,852	366,741	60,759	60,669	273,986	438,895	(20,378)	1,320,942	725,582
2031	896,560	374,915	63,721	64,482	277,010	453,717	(20,517)	1,332,742	777,146
2032	932,061	353,317	56,049	65,208	287,300	469,389	(22,228)	1,381,949	759,147
2033	972,384	384,255	62,192	69,219	295,368	484,194	(23,331)	1,447,333	796,948
2034	1,005,774	440,963	61,944	71,341	308,964	587,821	(25,717)	1,519,212	931,879
2035	1,045,753	427,939	68,232	75,291	282,174	634,767	(37,848)	1,320,576	1,175,732
2036	1,059,905	408,484	64,365	76,377	283,389	681,844	(37,612)	1,302,232	1,234,519
2037	1,098,698	646,990	68,268	81,120	320,408	866,956	(38,448)	1,691,138	1,352,854
2038	1,149,207	556,053	59,093	83,242	273,266	898,380	(42,737)	1,203,950	1,772,553
2039	1,162,572	608,953	72,149	66,290	131,738	656,251	(46,983)	1,295,449	1,355,521
2040	1,188,564	600,161	68,168	62,535	140,750	697,615	(55,879)	1,318,816	1,383,097
2041	1,208,450	597,641	70,617	56,414	144,670	730,200	(45,067)	1,336,999	1,425,926
2042	1,227,456	594,161	71,346	47,377	146,314	760,796	(46,179)	1,364,643	1,436,628
2043	1,258,698	601,972	74,677	42,639	148,028	799,261	(46,790)	1,418,924	1,459,559
2044	1,295,892	592,592	71,263	37,592	153,011	797,672	(48,533)	1,427,136	1,472,354
2045	1,333,912	635,925	81,629	33,678	159,466	786,086	(49,290)	1,496,830	1,484,575
2046	1,378,248	624,112	80,584	31,626	164,529	793,512	(48,200)	1,502,872	1,521,539
2047	1,417,026	651,728	86,187	29,140	171,872	799,493	(41,360)	1,563,956	1,550,131
2048	1,433,367	630,626	83,301	26,003	177,013	762,265	(42,456)	1,545,527	1,524,592

Indiana & Michigan POWER COMPANY
INTEGRATED RESOURCE PLAN
RP1 retires (12/31/2028) & RP2 lease extension + RP 2 FGD (12/31/2028) + RP2 Retirement (12/31/2048) CASE 8a No Carbon Commodity Pricing

	Resource (Capacity) Additions										Energy & Capacity Positions												Carbon Output		
	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)=(20)+(21)+(22)	(24)	(25)	(26)=(24)-(25)	(27)=(23)-(26)	(28)	(29)	(30)=(28)-(29)	(31)	(32)	(33)	
	(Current and Planned) Supply-Side + Purchased Unforced Capacity (UCAP)		(Increm) EE+ VVO + DR + Battery		Distributed Solar		Generic Wind		Utility Solar		Thermal Generation + Hydro	(Current) Purchased Energy Including OVEC	(New) Generic Wind + Utility Solar	= Market Sales	Load (Net of Embedded EE)	*Less:* (Increm) Energy Efficiency+ VVO+Dist Solar	= Net Load Requirements	ENERGY Surplus	Capacity	Peak + Reserves	CAPACITY Surplus	Reserve Margin	Existing Units CO2 Emissions	Total System CO2	
	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	%	tons	tons	
2019	4,417	4,417	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	25,842	2,383	0	28,225	23,943	0	23,943	4,282	4,417	4,339	78	10.8	11,833,150	11,833,150	2019
2020	46	4,463	18.6	18.6	0.0	0.0	0.0	0.0	0.0	0.0	28,949	2,339	0	31,287	22,817	76	22,741	8,546	4,482	4,059	423	20.2	12,189,745	12,189,745	2020
2021	11	4,474	17.4	36.1	0.0	0.0	0.0	0.0	0.0	0.0	28,334	2,360	0	30,694	22,233	146	22,086	8,607	4,510	4,078	432	20.4	12,005,610	12,005,610	2021
2022	29	4,503	23.5	59.6	10.4	10.4	36.9	36.9	0.0	0.0	28,124	2,552	992	31,668	22,367	241	22,125	9,542	4,610	4,104	506	22.3	12,436,224	12,448,593	2022
2023	411	4,914	9.0	68.6	2.1	12.4	18.5	55.4	0.0	0.0	28,845	2,614	1,524	32,983	22,332	282	22,050	10,933	5,050	4,088	963	34.5	12,141,770	12,153,342	2023
2024	0	4,914	7.6	76.2	2.5	14.9	0.0	55.4	0.0	0.0	28,916	2,632	1,533	33,081	22,270	319	21,951	11,131	5,060	4,090	971	34.7	12,324,033	12,335,961	2024
2025	(1,032)	3,882	30.5	106.7	0.8	15.7	0.0	55.4	25.4	25.4	28,024	2,638	1,632	32,294	22,277	368	21,909	10,384	4,085	4,082	3	8.9	12,311,512	12,333,498	2025
2026	(50)	3,832	9.5	116.2	0.8	16.6	0.0	55.4	50.9	76.3	25,581	2,632	1,846	30,059	22,270	412	21,858	8,201	4,096	4,082	14	9.3	8,737,966	8,758,829	2026
2027	(100)	3,732	8.0	124.2	0.8	17.4	0.0	55.4	76.3	152.6	25,132	2,650	2,168	29,950	22,257	449	21,807	8,143	4,082	4,081	0	8.9	8,399,965	8,420,969	2027
2028	(44)	3,688	21.7	145.9	1.2	18.6	0.0	55.4	76.3	228.9	23,308	2,686	2,501	28,495	22,304	458	21,847	6,648	4,137	4,104	33	9.7	7,310,452	7,340,824	2028
2029	(40)	3,648	(10.4)	135.6	1.7	20.3	0.0	55.4	76.3	305.1	26,099	2,468	2,813	31,379	22,375	420	21,955	9,425	4,164	4,110	54	10.3	9,092,507	9,122,990	2029
2030	0	3,648	10.1	145.7	1.7	21.9	0.0	55.4	101.7	406.8	25,585	2,304	3,242	31,131	22,395	467	21,928	9,203	4,278	4,119	159	13.1	8,683,437	8,714,579	2030
2031	0	3,648	0.2	145.9	1.7	23.6	0.0	55.4	76.3	483.1	24,940	2,301	3,564	30,806	22,432	474	21,958	8,847	4,356	4,130	226	14.8	8,886,321	8,917,112	2031
2032	(13)	3,635	1.7	147.6	1.7	25.3	0.0	55.4	76.3	559.4	24,877	2,315	3,899	31,091	22,482	487	21,995	9,096	4,423	4,154	269	15.9	7,794,829	7,827,881	2032
2033	0	3,635	(0.1)	147.4	2.5	27.7	0.0	55.4	76.3	635.7	25,276	2,309	4,208	31,793	22,543	496	22,048	9,745	4,501	4,157	344	17.9	8,383,138	8,418,954	2033
2034	(432)	3,203	13.3	160.7	2.1	29.8	18.5	73.8	76.3	712.0	25,337	2,273	5,063	32,673	22,612	499	22,114	10,559	4,179	4,179	0	8.9	8,192,044	8,931,980	2034
2035	(100)	3,103	17.4	178.1	1.7	31.5	18.5	92.3	76.3	788.3	19,717	1,617	5,917	27,251	22,676	510	22,166	5,085	4,193	4,193	0	8.9	8,755,053	9,493,328	2035
2036	(57)	3,046	10.3	188.5	1.7	33.1	18.5	110.7	76.3	864.5	18,212	1,626	6,796	26,633	22,727	497	22,230	4,403	4,243	4,217	26	9.5	8,173,626	8,902,968	2036
2037	(22)	3,024	(21.2)	167.3	1.7	34.8	18.5	129.2	0.0	864.5	24,665	1,607	7,303	33,575	22,774	478	22,297	11,279	4,220	4,217	3	8.9	8,449,449	11,218,830	2037
2038	0	3,024	40.2	207.5	1.7	36.4	18.5	147.6	0.0	864.5	14,176	1,603	7,835	23,614	22,831	470	22,362	1,253	4,280	4,231	49	10.1	7,300,220	10,124,230	2038
2039	0	3,024	6.1	213.6	2.1	38.5	18.5	166.1	0.0	864.5	15,054	1,598	8,368	25,019	22,895	443	22,452	2,567	4,307	4,245	61	10.4	8,535,884	11,232,448	2039
2040	(56)	2,968	4.9	218.5	1.7	40.2	18.5	184.5	0.0	864.5	14,502	1,424	8,940	24,866	22,945	419	22,526	2,340	4,276	4,276	0	8.9	7,771,634	10,473,371	2040
2041	0	2,968	15.2	233.8	2.1	42.2	18.5	203.0	0.0	864.5	13,951	751	9,432	24,135	22,987	436	22,551	1,584	4,312	4,276	36	9.8	7,128,638	9,591,627	2041
2042	(50)	2,918	17.8	251.6	2.1	44.3	18.5	221.4	0.0	864.5	13,457	752	9,964	24,173	23,030	462	22,568	1,605	4,300	4,288	12	9.2	7,050,647	9,359,512	2042
2043	(50)	2,868	28.8	280.4	2.1	46.4	18.5	239.9	0.0	864.5	13,259	753	10,496	24,508	23,079	528	22,551	1,957	4,299	4,299	0	8.9	7,224,643	9,399,029	2043
2044	0	2,868	20.6	301.0	2.5	48.9	0.0	239.9	0.0	864.5	12,648	754	10,545	23,946	23,125	566	22,560	1,386	4,322	4,322	0	8.9	6,748,862	8,869,713	2044
2045	0	2,868	6.7	307.7	2.5	51.3	0.0	239.9	0.0	864.5	13,182	754	10,496	24,432	23,177	561	22,616	1,816	4,331	4,329	3	8.9	7,567,571	9,588,222	2045
2046	0	2,868	26.3	334.0	2.5	53.8	0.0	239.9	0.0	864.5	12,583	718	10,496	23,797	23,238	615	22,622	1,174	4,360	4,341	19	9.4	7,312,488	9,205,777	2046
2047	0	2,868	18.0	352.1	2.9	56.7	0.0	239.9	0.0	864.5	12,831	603	10,496	23,930	23,296	639	22,656	1,274	4,381	4,353	28	9.6	7,654,597	9,513,226	2047
2048	0	2,868	(19.4)	332.6	2.9	59.6	0.0	239.9	0.0	864.5	12,099	604	10,543	23,246	23,081	558	22,523	722	4,365	4,365	0	8.9	7,241,190	8,983,162	2048

Indiana & Michigan POWER COMPANY
INTEGRATED RESOURCE PLAN

RP1 retires (12/31/2028) & RP2 no lease extension (12/31/2022) CASE 10
Base Band Commodity Pricing 12 YR Peaking Plan

Utility Costs (Nominal$000)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(1)thru(7)-(8)
	Load Cost	Fuel Costs	Emission Costs	Existing System FOM + OGC	(Incremental) Fixed + Variable + Lease Costs +ST PPA	(Incremental) Capital + Renewable + VVO Program Costs	Contract (Revenue)/Cost	*Less:* Market Revenue	GRAND TOTAL, Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000
2019	678,067	364,680	24,194	29,683	193,358	0	43,387	757,369	576,000
2020	653,672	368,811	24,193	35,392	205,458	15,800	44,403	845,324	502,407
2021	642,024	363,181	23,997	40,613	206,172	16,022	44,832	840,577	496,264
2022	670,720	372,595	24,605	50,293	214,715	75,067	39,336	907,582	539,748
2023	697,906	245,732	13,638	37,520	94,435	136,011	36,163	835,324	426,081
2024	727,080	248,361	13,667	49,700	97,746	140,603	34,582	877,550	434,189
2025	750,837	254,078	14,024	41,771	100,034	190,644	34,187	908,558	477,016
2026	773,155	235,862	13,766	44,934	108,543	233,569	30,309	974,867	465,272
2027	802,988	247,057	13,909	45,395	114,411	276,487	28,066	1,043,100	485,215
2028	1,004,061	252,140	83,189	50,938	138,194	373,732	16,580	1,328,138	590,697
2029	1,011,147	113,110	784	38,228	141,914	429,249	9,317	1,188,728	555,021
2030	1,033,175	117,122	752	38,228	146,571	481,458	(1,209)	1,254,956	561,142
2031	1,050,471	110,855	665	38,228	147,477	507,624	(646)	1,270,447	584,228
2032	1,081,557	121,123	955	38,228	157,131	543,425	(1,580)	1,382,130	558,710
2033	1,105,223	122,996	979	38,228	161,521	566,331	(9,269)	1,418,986	567,023
2034	1,136,325	285,741	30,619	38,228	183,496	709,600	(11,588)	1,636,189	736,231
2035	1,181,663	246,964	31,328	38,228	154,361	742,035	(23,437)	1,398,721	972,421
2036	1,190,603	232,872	30,106	38,228	153,305	744,269	(22,419)	1,347,966	1,018,999
2037	1,226,123	404,195	58,743	38,228	187,294	895,368	(22,757)	1,655,244	1,131,950
2038	1,270,871	344,982	60,271	38,228	140,422	897,007	(26,502)	1,183,220	1,542,060
2039	1,305,270	354,026	61,928	33,438	146,606	884,369	(30,398)	1,202,357	1,552,881
2040	1,330,720	405,071	71,500	29,682	157,601	950,002	(42,150)	1,294,822	1,607,604
2041	1,350,531	361,739	63,226	23,561	158,062	950,184	(45,208)	1,224,234	1,637,863
2042	1,388,191	361,530	62,812	14,524	161,795	947,913	(46,325)	1,241,559	1,648,881
2043	1,411,141	326,260	56,725	12,155	163,781	948,227	(46,938)	1,200,298	1,671,053
2044	1,466,439	342,764	58,964	9,631	169,334	948,238	(48,687)	1,248,509	1,698,175
2045	1,495,103	293,450	50,261	7,674	170,961	947,346	(49,443)	1,191,355	1,723,997
2046	1,541,599	286,286	48,926	5,623	176,142	948,638	(48,358)	1,199,226	1,759,630
2047	1,584,176	276,264	47,517	3,136	181,609	952,201	(41,520)	1,206,694	1,796,689
2048	1,606,514	281,509	48,574	0	188,554	930,576	(42,624)	1,232,371	1,780,732

Indiana & Michigan POWER COMPANY
INTEGRATED RESOURCE PLAN
RP1 retires (12/31/2028) & RP2 no lease extension (12/31/2022) CASE 10 Base Band Commodity Pricing 12 YR Peaking Plan

	Resource (Capacity) Additions										Energy & Capacity Positions												Carbon Output		
	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)=(20)+(21)+(22)	(24)	(25)	(26)=(24)-(25)	(27)=(23)-(26)	(28)	(29)	(30)=(28)-(29)	(31)	(32)	(33)	
	(Current and Planned) Supply-Side + Purchased Unforced Capacity (UCAP)		(Increm) EE+ VVO + DR + Battery		Distributed Solar		Generic Wind		Utility Solar		Thermal Generation + Hydro	(Current) Purchased Energy Including OVEC	(New) Generic Wind + Utility Solar	= Market Sales	Load (Net of Embedded EE)	*Less:* (Increm) Energy Efficiency+ VVO+Dist Solar	= Net Load Requirements	ENERGY Surplus	Capacity	Peak + Reserves	CAPACITY Surplus	Reserve Margin	Existing Units CO2 Emissions	Total System CO2	
	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	%	tons	tons	
2019	4,417	4,417	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	26,221	2,712	0	28,932	23,943	0	23,943	4,989	4,417	4,339	78	10.8	12,188,418	12,188,418	2019
2020	46	4,463	33.0	33.0	0.0	0.0	0.0	0.0	0.0	0.0	28,937	2,669	0	31,606	22,817	76	22,741	8,865	4,496	4,059	437	20.6	12,244,217	12,244,217	2020
2021	11	4,474	31.8	64.8	0.0	0.0	0.0	0.0	0.0	0.0	28,427	2,689	0	31,116	22,233	146	22,086	9,029	4,539	4,078	461	21.2	12,121,702	12,121,702	2021
2022	29	4,503	39.7	104.5	10.4	10.4	36.9	36.9	76.3	76.3	28,147	2,881	1,314	32,342	22,367	251	22,116	10,226	4,731	4,104	627	25.5	12,486,557	12,498,609	2022
2023	(799)	3,704	40.4	144.9	2.1	12.4	36.9	73.8	76.3	152.6	23,684	2,943	2,628	29,256	22,332	364	21,968	7,287	4,088	4,088	0	8.9	7,084,506	7,096,143	2023
2024	(50)	3,654	24.3	169.2	2.5	14.9	0.0	73.8	25.4	178.0	23,571	2,963	2,749	29,282	22,270	411	21,858	7,424	4,090	4,090	0	8.9	6,919,992	6,932,017	2024
2025	18	3,672	39.3	208.5	0.8	15.7	18.5	92.3	76.3	254.3	22,784	2,967	3,590	29,341	22,277	437	21,840	7,501	4,243	4,082	160	13.1	7,048,181	7,070,394	2025
2026	0	3,672	23.1	231.6	0.8	16.6	18.5	110.7	76.3	330.6	22,732	2,961	4,444	30,137	22,270	477	21,793	8,344	4,361	4,082	279	16.3	5,952,319	5,973,309	2026
2027	0	3,672	21.7	253.3	0.8	17.4	18.5	129.2	76.3	406.8	22,648	2,980	5,298	30,927	22,257	511	21,746	9,181	4,479	4,081	397	19.5	5,964,764	5,986,086	2027
2028	(595)	3,077	48.2	301.4	1.2	18.6	18.5	147.6	152.6	559.4	21,942	2,829	6,503	31,274	22,304	572	21,733	9,541	4,104	4,104	0	8.9	5,754,443	5,817,917	2028
2029	(157)	2,920	(3.2)	298.2	1.7	20.3	18.5	166.1	152.6	712.0	18,034	2,589	7,651	28,274	22,375	507	21,868	6,406	4,117	4,110	6	9.0	725,348	781,019	2029
2030	(150)	2,770	30.4	328.6	1.7	21.9	18.5	184.5	101.7	813.7	17,908	2,415	8,613	28,936	22,395	577	21,817	7,118	4,119	4,119	0	8.9	705,266	756,886	2030
2031	(50)	2,720	(5.0)	323.7	1.7	23.6	18.5	203.0	50.9	864.5	17,058	2,394	9,360	28,811	22,432	563	21,870	6,942	4,135	4,130	5	9.0	681,402	725,492	2031
2032	(13)	2,707	11.8	335.5	1.7	25.3	18.5	221.4	0.0	864.5	18,110	2,412	9,934	30,456	22,482	598	21,884	8,572	4,154	4,154	0	8.9	695,758	756,925	2032
2033	0	2,707	(9.2)	326.3	2.5	27.7	18.5	239.9	0.0	864.5	17,923	2,090	10,424	30,437	22,543	572	21,972	8,465	4,165	4,157	8	9.1	686,265	746,818	2033
2034	88	2,795	(2.8)	323.5	2.1	29.8	0.0	239.9	0.0	864.5	21,091	2,048	10,424	33,564	22,612	566	22,046	11,518	4,253	4,179	74	10.8	691,106	2,521,555	2034
2035	0	2,795	(10.6)	312.9	1.7	31.5	18.5	258.3	0.0	864.5	14,845	1,408	10,956	27,209	22,676	581	22,094	5,114	4,262	4,193	69	10.7	700,076	2,509,575	2035
2036	(7)	2,788	(14.7)	298.2	1.7	33.1	0.0	258.3	0.0	864.5	13,609	1,378	11,004	25,992	22,727	570	22,158	3,834	4,242	4,217	25	9.5	674,905	2,355,040	2036
2037	28	2,816	(51.9)	246.3	1.7	34.8	0.0	258.3	0.0	864.5	18,278	1,374	10,956	30,608	22,774	551	22,223	8,385	4,220	4,217	3	8.9	687,037	3,854,427	2037
2038	0	2,816	9.4	255.7	1.7	36.4	0.0	258.3	0.0	864.5	8,686	1,382	10,956	21,024	22,831	514	22,317	(1,293)	4,231	4,231	0	8.9	695,223	3,835,123	2038
2039	50	2,866	(32.3)	223.4	2.1	38.5	0.0	258.3	0.0	864.5	8,626	1,382	10,956	20,964	22,895	438	22,457	(1,494)	4,251	4,245	6	9.0	693,847	3,810,945	2039
2040	179	3,045	(26.0)	197.3	1.7	40.2	0.0	258.3	0.0	864.5	9,612	1,150	11,009	21,770	22,945	404	22,541	(770)	4,405	4,276	130	12.2	436,977	3,914,206	2040
2041	0	3,045	(15.0)	182.3	2.1	42.2	0.0	258.3	0.0	864.5	8,242	754	10,956	19,952	22,987	416	22,572	(2,619)	4,392	4,276	116	11.8	0	2,970,856	2041
2042	0	3,045	(12.1)	170.2	2.1	44.3	0.0	258.3	0.0	864.5	7,915	754	10,956	19,625	23,030	436	22,594	(2,969)	4,382	4,288	95	11.3	0	2,851,591	2042
2043	0	3,045	(9.8)	160.4	2.1	46.4	0.0	258.3	0.0	864.5	6,930	755	10,956	18,641	23,079	465	22,615	(3,974)	4,375	4,299	76	10.8	0	2,488,135	2043
2044	0	3,045	(8.8)	151.6	2.5	48.9	0.0	258.3	0.0	864.5	6,961	756	11,008	18,724	23,125	499	22,626	(3,902)	4,368	4,322	46	10.0	0	2,498,921	2044
2045	0	3,045	(0.2)	151.5	2.5	51.3	0.0	258.3	0.0	864.5	5,754	756	10,956	17,466	23,177	564	22,613	(5,147)	4,371	4,329	42	9.9	0	2,058,046	2045
2046	0	3,045	5.6	157.0	2.5	53.8	0.0	258.3	0.0	864.5	5,418	720	10,956	17,094	23,238	596	22,641	(5,547)	4,379	4,341	38	9.8	0	1,935,631	2046
2047	0	3,045	0.6	157.6	2.9	56.7	0.0	258.3	0.0	864.5	5,090	605	10,956	16,651	23,296	624	22,672	(6,021)	4,382	4,353	29	9.6	0	1,816,328	2047
2048	0	3,045	(20.4)	137.2	2.9	59.6	0.0	258.3	0.0	864.5	5,030	607	11,006	16,642	23,081	546	22,535	(5,893)	4,365	4,365	0	8.9	0	1,793,926	2048

Indiana & Michigan POWER COMPANY
INTEGRATED RESOURCE PLAN

RP1 retires (12/31/2028) & RP2 no lease extension (12/31/2022) CASE 11 Base Band Commodity Pricing 15 YR Peaking Plan

	Utility Costs (Nominal$000)								
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(1)thru(7)-(8)
	Load Cost	Fuel Costs	Emission Costs	Existing System FOM + OGC	(Incremental) Fixed + Variable + Lease Costs +ST PPA	(Incremental) Capital + Renewable + VVO Program Costs	Contract (Revenue)/Cost	*Less:* Market Revenue	GRAND TOTAL, Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000
2019	678,067	364,680	24,194	29,683	193,358	0	43,387	757,369	576,000
2020	653,672	368,811	24,193	35,392	205,458	16,439	44,403	845,439	502,930
2021	642,024	363,181	23,997	40,613	206,172	16,603	44,832	840,784	496,638
2022	670,720	372,595	24,605	50,293	214,715	77,077	39,336	908,044	541,297
2023	697,906	245,732	13,638	37,520	94,063	137,963	36,163	835,407	427,578
2024	727,080	248,361	13,667	49,700	97,364	140,614	34,582	877,674	433,693
2025	750,837	254,078	14,024	41,771	99,643	189,037	34,187	908,080	475,496
2026	773,155	235,862	13,766	44,934	108,142	231,962	30,309	974,125	464,005
2027	802,988	247,057	13,909	45,395	114,411	276,654	28,066	1,043,371	485,110
2028	1,004,061	252,140	83,189	50,938	138,615	372,576	16,580	1,328,122	589,979
2029	1,011,147	113,110	784	38,228	141,854	429,302	9,317	1,186,957	556,786
2030	1,033,175	117,122	752	38,228	146,971	487,201	(1,209)	1,254,222	568,019
2031	1,050,471	110,855	665	38,228	148,115	528,891	(646)	1,276,436	600,144
2032	1,081,557	121,123	955	38,228	158,114	557,886	(1,580)	1,387,351	568,933
2033	1,105,223	122,996	979	38,228	162,952	582,010	(9,269)	1,424,520	578,599
2034	1,136,325	125,681	3,161	38,228	195,782	739,495	(11,588)	1,422,829	804,256
2035	1,181,663	89,521	4,301	38,228	168,269	742,378	(23,437)	1,162,462	1,038,460
2036	1,190,603	78,106	3,140	38,228	169,352	740,190	(22,419)	1,117,055	1,080,147
2037	1,226,123	248,484	31,779	38,228	204,403	893,147	(22,757)	1,424,142	1,195,266
2038	1,270,871	189,415	33,197	38,228	159,479	893,241	(26,502)	952,470	1,605,459
2039	1,305,270	193,763	34,010	33,438	164,551	894,456	(30,398)	969,882	1,625,208
2040	1,330,720	249,876	44,249	29,682	176,628	941,011	(42,150)	1,069,510	1,660,506
2041	1,350,531	216,120	37,838	23,561	177,574	939,756	(45,208)	1,015,345	1,684,828
2042	1,388,191	216,951	37,761	14,524	181,797	942,062	(46,325)	1,033,033	1,701,928
2043	1,411,141	191,610	33,344	12,155	184,513	946,868	(46,938)	1,007,093	1,725,599
2044	1,466,439	201,285	34,663	9,631	190,465	945,228	(48,687)	1,045,173	1,753,852
2045	1,495,103	171,735	29,434	7,674	193,536	944,669	(49,443)	1,016,006	1,776,703
2046	1,541,599	166,975	28,549	5,623	199,452	945,753	(48,358)	1,029,209	1,810,384
2047	1,584,176	161,884	27,861	3,136	205,974	950,459	(41,520)	1,047,184	1,844,787
2048	1,606,514	164,417	28,388	0	212,880	913,277	(42,624)	1,064,190	1,818,663

Indiana & Michigan POWER COMPANY
INTEGRATED RESOURCE PLAN
RP1 retires (12/31/2028) & RP2 no lease extension (12/31/2022) CASE 11 Base Band Commodity Pricing 15 YR Peaking Plan

	Resource (Capacity) Additions										Energy & Capacity Positions												Carbon Output		
	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)=(20)+(21)+(22)	(24)	(25)	(26)=(24)-(25)	(27)=(23)-(26)	(28)	(29)	(30)=(28)-(29)	(31)	(32)	(33)	
	(Current and Planned) Supply-Side + Purchased Unforced Capacity (UCAP)		(Increm) EE+ VVO + DR + Battery		Distributed Solar		Generic Wind		Utility Solar		Thermal Generation + Hydro	(Current) Purchased Energy Including OVEC	(New) Generic Wind + Utility Solar	= Market Sales	Load (Net of Embedded EE)	*Less:* (Increm) Energy Efficiency+ VVO+Dist Solar	= Net Load Requirements	ENERGY Surplus	Capacity	Peak + Reserves	CAPACITY Surplus	Reserve Margin	Existing Units CO2 Emissions	Total System CO2	
	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	%	tons	tons	
2019	4,417	4,417	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	26,221	2,712	0	28,932	23,943	0	23,943	4,989	4,417	4,339	78	10.8	12,188,418	12,188,418	2019
2020	46	4,463	33.7	33.7	0.0	0.0	0.0	0.0	0.0	0.0	28,937	2,669	0	31,606	22,817	80	22,737	8,869	4,497	4,059	438	20.6	12,244,217	12,244,217	2020
2021	11	4,474	32.4	66.2	0.0	0.0	0.0	0.0	0.0	0.0	28,427	2,689	0	31,116	22,233	153	22,079	9,036	4,540	4,078	462	21.2	12,121,702	12,121,702	2021
2022	29	4,503	41.7	107.9	10.4	10.4	36.9	36.9	76.3	76.3	28,147	2,881	1,314	32,342	22,367	266	22,101	10,241	4,734	4,104	631	25.6	12,486,557	12,498,609	2022
2023	(799)	3,704	36.9	144.8	2.1	12.4	36.9	73.8	76.3	152.6	23,684	2,943	2,628	29,256	22,332	366	21,966	7,290	4,088	4,088	0	8.9	7,084,506	7,096,143	2023
2024	(50)	3,654	24.3	169.1	2.5	14.9	0.0	73.8	25.4	178.0	23,571	2,963	2,749	29,282	22,270	415	21,854	7,428	4,090	4,090	0	8.9	6,919,992	6,932,017	2024
2025	18	3,672	35.1	204.2	0.8	15.7	18.5	92.3	76.3	254.3	22,784	2,967	3,590	29,341	22,277	423	21,854	7,487	4,238	4,082	156	13.0	7,048,181	7,070,394	2025
2026	0	3,672	21.5	225.7	0.8	16.6	18.5	110.7	76.3	330.6	22,732	2,961	4,444	30,137	22,270	456	21,814	8,323	4,355	4,082	274	16.2	5,952,319	5,973,309	2026
2027	0	3,672	29.2	254.9	0.8	17.4	18.5	129.2	76.3	406.8	22,648	2,980	5,298	30,927	22,257	518	21,738	9,189	4,480	4,081	399	19.5	5,964,764	5,986,086	2027
2028	(595)	3,077	46.5	301.4	1.2	18.6	18.5	147.6	152.6	559.4	21,942	2,829	6,503	31,274	22,304	572	21,733	9,541	4,104	4,104	0	8.9	5,754,443	5,817,917	2028
2029	(157)	2,920	16.2	317.5	1.7	20.3	18.5	166.1	127.1	686.6	18,034	2,589	7,544	28,167	22,375	582	21,793	6,374	4,110	4,110	0	8.9	725,348	781,019	2029
2030	(150)	2,770	36.5	354.1	1.7	21.9	18.5	184.5	101.7	788.3	17,908	2,415	8,505	28,828	22,395	676	21,718	7,110	4,119	4,119	0	8.9	705,266	756,886	2030
2031	(100)	2,670	15.2	369.3	1.7	23.6	18.5	203.0	76.3	864.5	17,058	2,394	9,360	28,811	22,432	684	21,749	7,062	4,130	4,130	0	8.9	681,402	725,492	2031
2032	(13)	2,657	16.2	385.5	1.7	25.3	18.5	221.4	0.0	864.5	18,110	2,412	9,934	30,456	22,482	695	21,787	8,669	4,154	4,154	0	8.9	695,758	756,925	2032
2033	0	2,657	4.5	390.1	2.5	27.7	18.5	239.9	0.0	864.5	17,923	2,090	10,424	30,437	22,543	666	21,877	8,560	4,179	4,157	22	9.4	686,265	746,818	2033
2034	(25)	2,632	12.1	402.2	2.1	29.8	18.5	258.3	0.0	864.5	16,446	2,048	10,956	29,451	22,612	665	21,947	7,504	4,187	4,179	8	9.1	691,106	880,068	2034
2035	0	2,632	4.6	406.8	1.7	31.5	0.0	258.3	0.0	864.5	10,372	1,408	10,956	22,736	22,676	685	21,990	745	4,193	4,193	0	8.9	700,076	948,486	2035
2036	43	2,675	(5.8)	401.0	1.7	33.1	0.0	258.3	0.0	864.5	9,350	1,378	11,004	21,732	22,727	665	22,063	(330)	4,232	4,217	15	9.2	674,905	850,124	2036
2037	28	2,703	(40.4)	360.5	1.7	34.8	0.0	258.3	0.0	864.5	14,175	1,374	10,956	26,505	22,774	634	22,140	4,365	4,221	4,217	4	9.0	687,037	2,400,542	2037
2038	0	2,703	26.6	387.1	1.7	36.4	0.0	258.3	0.0	864.5	4,675	1,382	10,956	17,013	22,831	618	22,213	(5,200)	4,249	4,231	18	9.3	695,223	2,424,659	2038
2039	0	2,703	(6.3)	380.9	2.1	38.5	0.0	258.3	0.0	864.5	4,634	1,382	10,956	16,972	22,895	603	22,292	(5,321)	4,245	4,245	0	8.9	693,847	2,405,723	2039
2040	179	2,882	(28.2)	352.7	1.7	40.2	0.0	258.3	0.0	864.5	5,825	1,150	11,009	17,983	22,945	558	22,387	(4,404)	4,398	4,276	122	12.0	436,977	2,588,883	2040
2041	0	2,882	(17.7)	334.9	2.1	42.2	0.0	258.3	0.0	864.5	4,897	754	10,956	16,607	22,987	556	22,431	(5,824)	4,382	4,276	106	11.6	0	1,777,907	2041
2042	0	2,882	(15.5)	319.4	2.1	44.3	0.0	258.3	0.0	864.5	4,718	754	10,956	16,428	23,030	532	22,498	(6,070)	4,369	4,288	81	10.9	0	1,714,324	2042
2043	0	2,882	(3.7)	315.8	2.1	46.4	0.0	258.3	0.0	864.5	4,080	755	10,956	15,791	23,079	527	22,552	(6,762)	4,367	4,299	68	10.6	0	1,462,597	2043
2044	0	2,882	(1.8)	314.0	2.5	48.9	0.0	258.3	0.0	864.5	4,098	756	11,008	15,861	23,125	532	22,594	(6,733)	4,368	4,322	45	10.0	0	1,469,038	2044
2045	0	2,882	9.1	323.0	2.5	51.3	0.0	258.3	0.0	864.5	3,387	756	10,956	15,100	23,177	576	22,601	(7,501)	4,379	4,329	50	10.1	0	1,205,245	2045
2046	0	2,882	6.1	329.1	2.5	53.8	0.0	258.3	0.0	864.5	3,186	720	10,956	14,862	23,238	610	22,628	(7,766)	4,388	4,341	47	10.0	0	1,129,462	2046
2047	0	2,882	4.2	333.3	2.9	56.7	0.0	258.3	0.0	864.5	3,004	605	10,956	14,565	23,296	636	22,659	(8,094)	4,395	4,353	42	9.9	0	1,064,980	2047
2048	0	2,882	(33.2)	300.2	2.9	59.6	0.0	258.3	0.0	864.5	2,963	607	11,006	14,576	23,081	557	22,524	(7,949)	4,365	4,365	0	8.9	0	1,048,441	2048

Indiana & Michigan POWER COMPANY
INTEGRATED RESOURCE PLAN

RP1 retires (12/31/2028) & RP2 no lease extension (12/31/2022) CASE 12
Base Band Commodity Pricing 2X Renewables

	Utility Costs (Nominal$000)								
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(1)thru(7)-(8)
	Load Cost	Fuel Costs	Emission Costs	Existing System FOM + OGC	(Incremental) Fixed + Variable + Lease Costs +ST PPA	(Incremental) Capital + Renewable + VVO Program Costs	Contract (Revenue)/Cost	*Less:* Market Revenue	GRAND TOTAL, Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000
2019	678,067	364,680	24,194	29,683	193,358	0	43,387	757,369	576,000
2020	653,672	368,811	24,193	35,392	205,101	8,072	44,403	845,203	494,442
2021	642,024	363,181	23,997	40,613	205,444	8,139	44,832	840,334	487,897
2022	670,720	372,595	24,605	50,293	221,345	101,136	39,336	934,491	545,538
2023	697,906	245,732	13,638	37,520	106,154	176,343	36,163	876,656	436,800
2024	727,080	248,361	13,667	49,700	111,638	169,739	34,582	915,805	438,961
2025	750,837	254,078	14,024	41,771	117,447	218,906	34,187	942,918	488,331
2026	773,155	235,862	13,766	44,934	129,660	249,439	30,309	1,004,584	472,541
2027	802,988	247,057	13,909	45,395	138,814	334,637	28,066	1,105,189	505,678
2028	1,004,061	250,018	82,818	50,938	158,350	453,581	16,580	1,449,434	566,913
2029	1,011,147	111,291	461	38,228	162,180	541,422	9,317	1,337,585	536,461
2030	1,033,175	115,436	456	38,228	171,213	597,234	(1,209)	1,415,400	539,134
2031	1,050,471	109,391	411	38,228	179,543	685,813	(646)	1,480,937	582,275
2032	1,081,557	118,234	444	38,228	197,818	776,268	(1,580)	1,655,647	555,323
2033	1,105,223	120,011	449	38,228	210,512	869,163	(9,269)	1,758,346	575,972
2034	1,136,325	113,404	979	38,228	215,113	969,322	(11,588)	1,783,990	677,793
2035	1,181,663	72,322	1,229	38,228	185,486	1,035,324	(23,437)	1,584,428	906,388
2036	1,190,603	66,205	984	38,228	185,376	1,095,478	(22,419)	1,604,340	950,116
2037	1,226,123	81,998	2,873	38,228	234,450	1,295,937	(22,757)	1,747,215	1,109,638
2038	1,270,871	19,989	3,613	38,228	188,021	1,330,237	(26,502)	1,318,646	1,505,811
2039	1,305,270	19,772	3,592	33,438	193,131	1,334,840	(30,398)	1,342,997	1,516,646
2040	1,330,720	26,030	4,792	29,682	206,080	1,380,123	(42,150)	1,383,225	1,552,052
2041	1,350,531	13,686	2,482	23,561	207,714	1,376,939	(45,208)	1,366,781	1,562,925
2042	1,388,191	14,930	2,691	14,524	211,949	1,380,203	(46,325)	1,410,658	1,555,505
2043	1,411,141	7,784	1,398	12,155	218,403	1,367,831	(46,938)	1,428,062	1,543,712
2044	1,466,439	8,131	1,452	9,631	223,612	1,368,114	(48,687)	1,478,971	1,549,723
2045	1,495,103	6,168	1,086	7,674	227,461	1,370,484	(49,443)	1,501,370	1,557,165
2046	1,541,599	5,252	918	5,623	232,447	1,373,428	(48,358)	1,539,777	1,571,132
2047	1,584,176	6,107	1,076	3,136	237,443	1,389,463	(41,520)	1,582,752	1,597,130
2048	1,606,514	5,491	975	0	247,183	1,336,012	(42,624)	1,616,350	1,537,202

Indiana & Michigan POWER COMPANY
INTEGRATED RESOURCE PLAN
RP1 retires (12/31/2028) & RP2 no lease extension (12/31/2022) CASE 12 Base Band Commodity Pricing 2X Renewables

	Resource (Capacity) Additions										Energy & Capacity Positions												Carbon Output		
	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)=(20)+(21)+(22)	(24)	(25)	(26)=(24)-(25)	(27)=(23)-(26)	(28)	(29)	(30)=(28)-(29)	(31)	(32)	(33)	
	(Current and Planned) Supply-Side + Purchased Unforced Capacity (UCAP)		(Increm) EE+ VVO + DR + Battery		Distributed Solar		Generic Wind		Utility Solar		Thermal Generation + Hydro	(Current) Purchased Energy Including OVEC	(New) Generic Wind + Utility Solar	= Market Sales	Load (Net of Embedded EE)	*Less:* (Increm) Energy Efficiency+ VVO+Dist Solar	= Net Load Requirements	ENERGY Surplus	Capacity	Peak + Reserves	CAPACITY Surplus	Reserve Margin	Existing Units CO2 Emissions	Total System CO2	
	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	%	tons	tons	
2019	4,417	4,417	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	26,221	2,712	0	28,932	23,943	0	23,943	4,989	4,417	4,339	78	10.8	12,188,418	12,188,418	2019
2020	46	4,463	18.6	18.6	0.0	0.0	0.0	0.0	0.0	0.0	28,937	2,669	0	31,606	22,817	76	22,741	8,865	4,482	4,059	423	20.2	12,244,217	12,244,217	2020
2021	11	4,474	17.4	36.1	0.0	0.0	0.0	0.0	0.0	0.0	28,427	2,689	0	31,116	22,233	146	22,086	9,029	4,510	4,078	432	20.4	12,121,702	12,121,702	2021
2022	29	4,503	25.3	61.3	25.7	25.7	73.8	73.8	50.9	50.9	28,147	2,881	2,199	33,227	22,367	313	22,054	11,173	4,715	4,104	611	25.1	12,486,557	12,498,609	2022
2023	(849)	3,654	22.6	83.9	9.9	35.6	36.9	110.7	152.6	203.4	23,684	2,943	3,907	30,535	22,332	431	21,901	8,633	4,088	4,088	0	8.9	7,084,506	7,096,143	2023
2024	0	3,654	0.5	84.4	5.0	40.6	0.0	110.7	0.0	203.4	23,571	2,963	3,926	30,460	22,270	448	21,822	8,638	4,093	4,090	3	9.0	6,919,992	6,932,017	2024
2025	18	3,672	44.0	128.4	1.7	42.2	0.0	110.7	152.6	356.0	22,784	2,967	4,552	30,302	22,277	495	21,782	8,520	4,309	4,082	227	14.9	7,048,181	7,070,394	2025
2026	0	3,672	23.0	151.4	1.7	43.9	0.0	110.7	152.6	508.6	22,732	2,961	5,196	30,888	22,270	538	21,732	9,156	4,487	4,082	405	19.7	5,952,319	5,973,309	2026
2027	0	3,672	21.6	173.0	0.8	44.7	36.9	147.6	152.6	661.1	22,648	2,980	6,904	32,533	22,257	571	21,685	10,847	4,698	4,081	617	25.3	5,964,764	5,986,086	2027
2028	(943)	2,729	38.5	211.5	2.5	47.2	36.9	184.5	279.7	940.8	21,896	2,829	9,186	33,911	22,304	597	21,707	12,204	4,113	4,104	9	9.1	5,754,443	5,790,674	2028
2029	(207)	2,522	12.5	223.9	2.5	49.7	36.9	221.4	152.6	1,093.4	17,996	2,589	10,858	31,442	22,375	597	21,778	9,665	4,110	4,110	0	8.9	725,348	758,067	2029
2030	(100)	2,422	17.3	241.2	2.5	52.2	18.5	239.9	152.6	1,246.0	17,874	2,415	12,034	32,323	22,395	620	21,775	10,548	4,201	4,119	82	11.0	705,266	736,536	2030
2031	0	2,422	13.9	255.2	3.3	55.5	36.9	276.8	152.6	1,398.5	17,029	2,394	13,743	33,166	22,432	630	21,802	11,364	4,408	4,130	278	16.2	681,402	708,629	2031
2032	(13)	2,409	15.5	270.6	4.1	59.6	36.9	313.7	152.6	1,551.1	18,055	2,412	15,514	35,980	22,482	650	21,832	14,148	4,604	4,154	450	20.7	695,758	724,206	2032
2033	0	2,409	20.3	290.9	3.3	62.9	36.9	350.6	152.6	1,703.7	17,868	2,090	17,160	37,117	22,543	686	21,857	15,260	4,817	4,157	660	26.2	686,265	714,035	2033
2034	(719)	1,690	23.0	313.9	-4.1	58.8	36.9	387.5	25.4	1,729.1	16,225	2,048	18,332	36,605	22,612	703	21,909	14,696	4,179	4,179	0	8.9	691,106	749,634	2034
2035	(50)	1,640	27.0	340.9	0.0	58.8	36.9	424.4	0.0	1,729.1	10,071	1,408	19,396	30,874	22,676	748	21,928	8,947	4,193	4,193	0	8.9	700,076	771,072	2035
2036	(7)	1,633	10.3	351.1	0.0	58.8	36.9	461.3	0.0	1,729.1	9,146	1,378	20,548	31,072	22,727	728	21,999	9,073	4,233	4,217	16	9.3	674,905	729,845	2036
2037	(35)	1,598	(16.7)	334.5	0.0	58.8	36.9	498.2	0.0	1,729.1	9,894	1,374	21,525	32,793	22,774	728	22,046	10,747	4,218	4,217	1	8.9	687,037	841,962	2037
2038	(50)	1,548	45.1	379.5	0.0	58.8	18.5	516.6	0.0	1,729.1	441	1,382	22,057	23,880	22,831	738	22,093	1,787	4,232	4,231	1	8.9	695,223	883,434	2038
2039	0	1,548	13.2	392.7	0.0	58.8	0.0	516.6	0.0	1,729.1	428	1,382	22,057	23,867	22,895	727	22,168	1,699	4,245	4,245	0	8.9	693,847	874,637	2039
2040	42	1,590	(11.4)	381.3	0.0	58.8	0.0	516.6	0.0	1,729.1	517	1,150	22,162	23,828	22,945	682	22,263	1,565	4,276	4,276	0	8.9	436,977	670,019	2040
2041	0	1,590	0.2	381.5	0.0	58.8	0.0	516.6	0.0	1,729.1	317	754	22,057	23,128	22,987	685	22,302	826	4,276	4,276	0	8.9	0	116,641	2041
2042	0	1,590	11.7	393.2	0.0	58.8	0.0	516.6	0.0	1,729.1	326	754	22,057	23,137	23,030	730	22,300	837	4,288	4,288	0	8.9	0	122,161	2042
2043	50	1,640	(7.0)	386.2	0.0	58.8	0.0	516.6	0.0	1,729.1	222	755	22,057	23,034	23,079	705	22,374	659	4,331	4,299	32	9.7	0	61,318	2043
2044	0	1,640	2.5	388.7	0.0	58.8	0.0	516.6	0.0	1,729.1	222	756	22,160	23,138	23,125	716	22,409	729	4,333	4,322	11	9.1	0	61,547	2044
2045	0	1,640	13.6	402.3	0.0	58.8	0.0	516.6	0.0	1,729.1	192	756	22,057	23,005	23,177	769	22,408	597	4,347	4,329	18	9.3	0	44,476	2045
2046	0	1,640	5.2	407.5	0.0	58.8	0.0	516.6	0.0	1,729.1	178	720	22,057	22,955	23,238	788	22,450	505	4,352	4,341	11	9.2	0	36,313	2046
2047	0	1,640	6.0	413.5	0.0	58.8	0.0	516.6	0.0	1,729.1	186	605	22,057	22,848	23,296	807	22,488	360	4,358	4,353	5	9.0	0	41,134	2047
2048	50	1,690	(43.3)	370.2	0.0	58.8	0.0	516.6	0.0	1,729.1	177	607	22,156	22,940	23,081	677	22,404	536	4,365	4,365	0	8.9	0	36,014	2048

Indiana & Michigan POWER COMPANY
INTEGRATED RESOURCE PLAN

RP1 retires (12/31/2028) & RP2 no lease extension (12/31/2022) CASE 12A
Base Band Commodity Pricing 2X Renewables

	Utility Costs (Nominal$000)								
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(1)thru(7)-(8)
	Load Cost	Fuel Costs	Emission Costs	Existing System FOM + OGC	(Incremental) Fixed + Variable + Lease Costs +ST PPA	(Incremental) Capital + Renewable + VVO Program Costs	Contract (Revenue)/Cost	*Less:* Market Revenue	GRAND TOTAL, Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000
2019	678,067	364,680	24,194	29,683	193,358	0	43,387	757,369	576,000
2020	653,672	368,811	24,193	35,392	205,101	8,711	44,403	845,318	494,965
2021	642,024	363,181	23,997	40,613	205,444	8,720	44,832	840,540	488,271
2022	670,720	372,595	24,605	50,293	221,345	99,612	39,336	934,768	543,738
2023	697,906	245,732	13,638	37,520	106,060	173,416	36,163	877,144	433,290
2024	727,080	248,361	13,667	49,700	111,541	167,706	34,582	916,063	436,573
2025	750,837	254,078	14,024	41,771	116,090	200,047	34,187	939,002	472,031
2026	773,155	235,862	13,766	44,934	127,872	230,409	30,309	1,000,274	456,033
2027	802,988	247,057	13,909	45,395	136,585	315,432	28,066	1,100,427	489,006
2028	1,004,061	250,018	82,818	50,938	155,905	407,244	16,580	1,417,780	549,785
2029	1,011,147	111,291	461	38,228	160,259	500,048	9,317	1,309,278	521,474
2030	1,033,175	115,436	456	38,228	169,257	559,032	(1,209)	1,390,687	523,688
2031	1,050,471	109,391	411	38,228	177,437	644,855	(646)	1,455,614	564,534
2032	1,081,557	118,234	444	38,228	196,130	739,609	(1,580)	1,630,939	541,683
2033	1,105,223	120,011	449	38,228	208,782	832,904	(9,269)	1,733,775	562,554
2034	1,136,325	167,780	10,314	38,228	211,511	946,139	(11,588)	1,839,929	658,780
2035	1,181,663	126,236	10,494	38,228	182,480	1,009,177	(23,437)	1,637,611	887,231
2036	1,190,603	118,785	10,153	38,228	182,286	1,070,534	(22,419)	1,654,962	933,208
2037	1,226,123	290,511	38,987	38,228	216,662	1,285,539	(22,757)	2,033,086	1,040,208
2038	1,270,871	228,567	39,921	38,228	170,434	1,348,414	(26,502)	1,633,354	1,436,579
2039	1,305,270	234,600	41,024	33,438	174,418	1,349,029	(30,398)	1,660,927	1,446,454
2040	1,330,720	230,353	40,648	29,682	180,904	1,359,018	(42,150)	1,686,063	1,443,112
2041	1,350,531	206,571	36,102	23,561	180,191	1,363,503	(45,208)	1,651,188	1,464,064
2042	1,388,191	206,279	35,835	14,524	183,862	1,357,703	(46,325)	1,688,318	1,451,751
2043	1,411,141	186,658	32,453	12,155	186,482	1,357,056	(46,938)	1,686,291	1,452,715
2044	1,466,439	196,075	33,729	9,631	190,954	1,363,373	(48,687)	1,752,084	1,459,430
2045	1,495,103	167,950	28,766	7,674	192,398	1,363,694	(49,443)	1,734,535	1,471,607
2046	1,541,599	163,928	28,016	5,623	196,112	1,376,575	(48,358)	1,767,049	1,496,446
2047	1,584,176	158,111	27,196	3,136	203,083	1,345,369	(41,520)	1,796,023	1,483,528
2048	1,606,514	161,183	27,812	0	212,022	1,324,919	(42,624)	1,833,230	1,456,595

Indiana & Michigan POWER COMPANY
INTEGRATED RESOURCE PLAN
RP1 retires (12/31/2028) & RP2 no lease extension (12/31/2022) CASE 12A Base Band Commodity Pricing 2X Renewables

	Resource (Capacity) Additions										Energy & Capacity Positions												Carbon Output		
	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)=(20)+(21)+(22)	(24)	(25)	(26)=(24)-(25)	(27)=(23)-(26)	(28)	(29)	(30)=(28)-(29)	(31)	(32)	(33)	
	(Current and Planned) Supply-Side + Purchased Unforced Capacity (UCAP)		(Increm) EE+ VVO + DR + Battery		Distributed Solar		Generic Wind		Utility Solar		Thermal Generation + Hydro	(Current) Purchased Energy Including OVEC	(New) Generic Wind + Utility Solar	= Market Sales	Load (Net of Embedded EE)	*Less:* (Increm) Energy Efficiency+ VVO+Dist Solar	= Net Load Requirements	ENERGY Surplus	Capacity	Peak + Reserves	CAPACITY Surplus	Reserve Margin	Existing Units CO2 Emissions	Total System CO2	
	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	Ann MW	Cum MW	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	%	tons	tons	
2019	4,417	4,417	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	26,221	2,712	0	28,932	23,943	0	23,943	4,989	4,417	4,339	78	10.8	12,188,418	12,188,418	2019
2020	46	4,463	19.4	19.4	0.0	0.0	0.0	0.0	0.0	0.0	28,937	2,669	0	31,606	22,817	80	22,737	8,869	4,482	4,059	423	20.2	12,244,217	12,244,217	2020
2021	11	4,474	18.0	37.4	0.0	0.0	0.0	0.0	0.0	0.0	28,427	2,689	0	31,116	22,233	153	22,079	9,036	4,511	4,078	434	20.4	12,121,702	12,121,702	2021
2022	29	4,503	25.7	63.1	25.7	25.7	73.8	73.8	50.9	50.9	28,147	2,881	2,199	33,227	22,367	322	22,044	11,182	4,716	4,104	613	25.1	12,486,557	12,498,609	2022
2023	(849)	3,654	20.8	83.9	9.9	35.6	36.9	110.7	152.6	203.4	23,684	2,943	3,907	30,535	22,332	448	21,884	8,650	4,088	4,088	0	8.9	7,084,506	7,096,143	2023
2024	0	3,654	(1.3)	82.6	5.0	40.6	0.0	110.7	0.0	203.4	23,571	2,963	3,926	30,460	22,270	457	21,812	8,647	4,091	4,090	2	8.9	6,919,992	6,932,017	2024
2025	18	3,672	29.1	111.7	1.7	42.2	0.0	110.7	127.1	330.6	22,784	2,967	4,444	30,195	22,277	501	21,775	8,419	4,267	4,082	185	13.8	7,048,181	7,070,394	2025
2026	0	3,672	8.2	119.9	1.7	43.9	0.0	110.7	152.6	483.1	22,732	2,961	5,088	30,781	22,270	542	21,728	9,053	4,430	4,082	348	18.1	5,952,319	5,973,309	2026
2027	0	3,672	6.9	126.7	0.8	44.7	36.9	147.6	152.6	635.7	22,648	2,980	6,797	32,425	22,257	574	21,683	10,742	4,627	4,081	545	23.4	5,964,764	5,986,086	2027
2028	(743)	2,929	28.7	155.5	2.5	47.2	36.9	184.5	152.6	788.3	21,896	2,829	8,541	33,266	22,304	605	21,699	11,567	4,104	4,104	0	8.9	5,754,443	5,790,674	2028
2029	(207)	2,722	(2.7)	152.8	2.5	49.7	36.9	221.4	178.0	966.3	17,996	2,589	10,321	30,906	22,375	573	21,801	9,104	4,112	4,110	2	8.9	725,348	758,067	2029
2030	(300)	2,422	24.5	177.3	2.5	52.2	0.0	221.4	279.7	1,246.0	17,874	2,415	11,502	31,791	22,395	624	21,771	10,019	4,119	4,119	0	8.9	705,266	736,536	2030
2031	0	2,422	9.7	187.0	3.3	55.5	36.9	258.3	152.6	1,398.5	17,029	2,394	13,211	32,634	22,432	631	21,801	10,832	4,321	4,130	191	13.9	681,402	708,629	2031
2032	(13)	2,409	23.7	210.7	4.1	59.6	36.9	295.2	152.6	1,551.1	18,055	2,412	14,979	35,445	22,482	682	21,800	13,645	4,526	4,154	372	18.6	695,758	724,206	2032
2033	0	2,409	21.4	232.0	3.3	62.9	36.9	332.1	152.6	1,703.7	17,868	2,090	16,628	36,585	22,543	723	21,821	14,764	4,740	4,157	583	24.1	686,265	714,035	2033
2034	(632)	1,777	13.3	245.4	-4.1	58.8	36.9	369.0	25.4	1,729.1	17,791	2,048	17,800	37,639	22,612	700	21,912	15,727	4,179	4,179	0	8.9	691,106	1,307,666	2034
2035	0	1,777	18.5	263.9	0.0	58.8	36.9	405.9	0.0	1,729.1	11,587	1,408	18,864	31,858	22,676	710	21,965	9,893	4,235	4,193	42	9.9	700,076	1,306,220	2035
2036	(7)	1,770	11.1	275.0	0.0	58.8	36.9	442.8	0.0	1,729.1	10,582	1,378	20,013	31,973	22,727	695	22,032	9,941	4,276	4,217	58	10.4	674,905	1,241,507	2036
2037	28	1,798	(23.1)	251.9	0.0	58.8	36.9	479.7	0.0	1,729.1	15,380	1,374	20,993	37,746	22,774	666	22,108	15,638	4,317	4,217	100	11.5	687,037	2,789,199	2037
2038	0	1,798	41.3	293.2	0.0	58.8	36.9	516.6	0.0	1,729.1	5,808	1,382	22,057	29,247	22,831	650	22,181	7,066	4,396	4,231	165	13.1	695,223	2,774,950	2038
2039	0	1,798	8.3	301.5	0.0	58.8	0.0	516.6	0.0	1,729.1	5,768	1,382	22,057	29,207	22,895	626	22,269	6,938	4,404	4,245	159	12.9	693,847	2,758,756	2039
2040	(106)	1,692	4.7	306.2	0.0	58.8	0.0	516.6	0.0	1,729.1	5,527	1,150	22,162	28,839	22,945	592	22,354	6,485	4,303	4,276	27	9.6	436,977	2,413,769	2040
2041	(50)	1,642	23.2	329.5	0.0	58.8	0.0	516.6	0.0	1,729.1	4,759	754	22,057	27,569	22,987	628	22,360	5,210	4,276	4,276	0	8.9	0	1,696,367	2041
2042	0	1,642	11.8	341.2	0.0	58.8	0.0	516.6	0.0	1,729.1	4,569	754	22,057	27,380	23,030	620	22,410	4,970	4,288	4,288	0	8.9	0	1,626,855	2042
2043	0	1,642	12.2	353.5	0.0	58.8	0.0	516.6	0.0	1,729.1	4,013	755	22,057	26,825	23,079	628	22,451	4,374	4,300	4,299	1	8.9	0	1,423,488	2043
2044	0	1,642	22.2	375.7	0.0	58.8	0.0	516.6	0.0	1,729.1	4,030	756	22,160	26,946	23,125	688	22,438	4,509	4,322	4,322	0	8.9	0	1,429,447	2044
2045	0	1,642	6.8	382.6	0.0	58.8	0.0	516.6	0.0	1,729.1	3,341	756	22,057	26,154	23,177	715	22,462	3,692	4,329	4,329	0	8.9	0	1,177,897	2045
2046	0	1,642	11.7	394.3	0.0	58.8	0.0	516.6	0.0	1,729.1	3,150	720	22,057	25,927	23,238	743	22,494	3,432	4,341	4,341	0	8.9	0	1,108,396	2046
2047	50	1,692	(26.5)	367.7	0.0	58.8	0.0	516.6	0.0	1,729.1	2,961	605	22,057	25,623	23,296	695	22,601	3,022	4,364	4,353	11	9.1	0	1,039,539	2047
2048	50	1,742	(49.6)	318.2	0.0	58.8	0.0	516.6	0.0	1,729.1	2,927	607	22,156	25,690	23,081	554	22,527	3,163	4,365	4,365	0	8.9	0	1,027,156	2048

Exhibit D New Generation Resources

AEP System
New Generation Technologies
Key Supply-Side Resource Option Assumptions (a)(b)(c)

Type	Capability (MW) (d) Std. ISO	Capability (MW) (d) Summer	Capability (MW) (d) Winter	Installed Cost (c,e) ($/kW)	Full Load Heat Rate (HHV,Btu/kWh)	Fuel Cost ($/MBtu)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Capacity Factor (%)	LCOE (f) ($/MWh)
Base Load										
Nuclear	1,610	1,560	1,690	8,500	10,500	0.94	3.99	168.33	80	184.5
Pulv. Coal with Carbon Capture (PRB)	540	520	570	9,500	12,500	2.42	4.37	104.12	75	228.7
Combined Cycle (1X1 "J" Class)	610	800	820	900	6,200	3.42	1.77	12.86	75	60.4
Combined Cycle (2X1 "J" Class)	1,230	1,600	1,640	700	6,200	3.42	1.55	10.65	75	56.0
Combined Cycle (2X1 "H" Class)	1,150	1,490	1,530	700	6,300	3.42	1.51	11.07	75	56.9
Peaking										
Combustion Turbine (2 - "E" Class) (g)	180	190	190	1,200	11,700	3.42	4.05	30.46	25	151.7
Combustion Turbine (2 - "F" Class, w/evap coolers) (g)	490	500	510	700	10,000	3.42	6.27	24.55	25	118.4
Aero-Derivative (2 - Small Machines) (g)	120	120	120	1,100	9,900	3.42	2.51	32.17	25	138.7
Recip Engine Farm	220	220	230	1,300	8,300	3.42	5.36	13.91	25	130.6
Battery	10	10	10	1,900	83% (h)	0.00	0.00	38.99	25	161.3

Notes:
(a) Installed cost, capability and heat rate numbers have been rounded
(b) All costs in 2019 dollars, except as noted.
(c) $/kW costs are based on summer capability
(d) All Capabilities are at 1,000 feet above sea level
(e) Total Plant Investment Cost w/AFUDC (AEP-East rate of 5.5%,site rating $/kW)
(f) Levelized cost of energy based on capacity factors shown in table
(g) Includes SCR environmental installation
(h) Denotes efficiency, (w/ power electronics)

Exhibit E I&M Internal Hourly Load Data

Exhibit E

Indiana Michigan Power Company

Hourly Internal Load

Indiana Michigan Power Company - Hourly Internal Load (MW)
Note: Hours refelct EST

DATE	HR1	HR2	HR3	HR4	HR5	HR6	HR7	HR8	HR9	HR10	HR11	HR12
1/1/2018	2,865.7	2,808.1	2,821.2	2,798.5	2,807.7	2,831.3	2,873.4	2,932.9	2,906.3	2,996.4	3,060.6	3,067.5
1/2/2018	3,072.6	3,029.9	3,046.1	3,077.5	3,124.6	3,283.2	3,443.3	3,595.2	3,657.4	3,702.6	3,646.6	3,616.7
1/3/2018	3,308.6	3,255.8	3,164.9	3,221.4	3,277.7	3,363.7	3,512.2	3,599.5	3,631.5	3,620.6	3,667.3	3,647.2
1/4/2018	3,138.0	3,089.5	3,038.1	3,056.1	3,070.5	3,206.6	3,412.3	3,527.7	3,545.0	3,552.0	3,542.1	3,512.3
1/5/2018	3,142.6	3,088.3	3,097.8	3,100.8	3,152.6	3,269.3	3,444.3	3,583.5	3,594.2	3,610.5	3,570.7	3,549.8
1/6/2018	3,121.6	3,097.4	3,042.0	3,067.9	3,067.4	3,128.3	3,199.7	3,256.9	3,310.8	3,295.7	3,260.1	3,204.1
1/7/2018	2,993.6	2,862.1	2,927.9	2,914.6	2,945.9	2,965.9	3,031.5	3,079.8	3,113.6	3,125.9	3,154.3	3,112.4
1/8/2018	2,879.7	2,874.4	2,871.6	2,857.7	2,918.8	3,020.0	3,168.3	3,292.0	3,349.3	3,348.1	3,339.8	3,349.3
1/9/2018	2,839.1	2,796.3	2,759.9	2,754.9	2,835.5	2,976.8	3,239.8	3,351.2	3,318.9	3,208.4	3,306.0	3,277.8
1/10/2018	2,802.1	2,759.3	2,747.3	2,755.3	2,836.8	2,964.4	3,169.8	3,294.3	3,305.8	3,292.7	3,269.0	3,221.3
1/11/2018	2,587.8	2,515.8	2,507.8	2,512.0	2,565.2	2,685.2	2,891.4	2,907.2	2,909.4	2,872.3	2,904.0	2,884.2
1/12/2018	2,601.4	2,542.8	2,552.5	2,573.3	2,673.0	2,826.3	3,073.7	3,240.8	3,310.0	3,335.9	3,391.9	3,405.4
1/13/2018	2,968.2	2,908.2	2,874.0	2,848.3	2,857.6	2,908.8	2,995.7	3,040.1	3,126.3	3,180.6	3,165.2	3,084.5
1/14/2018	2,865.4	2,830.9	2,807.8	2,818.5	2,867.5	2,931.0	2,975.8	3,113.8	3,145.2	3,130.3	3,098.7	3,057.3
1/15/2018	3,048.7	3,033.7	2,984.0	3,020.7	3,078.4	3,200.2	3,354.3	3,475.8	3,532.3	3,532.0	3,579.4	3,558.9
1/16/2018	3,121.4	3,120.0	3,096.9	3,108.0	3,150.6	3,328.8	3,524.3	3,702.7	3,720.9	3,723.2	3,703.5	3,668.8
1/17/2018	3,211.3	3,148.6	3,153.4	3,151.3	3,229.4	3,360.3	3,567.1	3,702.5	3,710.7	3,628.6	3,590.5	3,485.4
1/18/2018	3,168.8	3,137.4	3,110.5	3,101.5	3,197.9	3,337.5	3,572.2	3,704.2	3,684.8	3,638.0	3,578.9	3,488.2
1/19/2018	3,033.4	2,966.3	2,954.0	2,975.6	3,042.8	3,108.2	3,354.4	3,501.7	3,470.0	3,405.8	3,354.3	3,321.7
1/20/2018	2,721.0	2,640.4	2,616.7	2,584.1	2,647.0	2,699.5	2,733.4	2,773.7	2,870.9	2,866.8	2,845.7	2,802.6
1/21/2018	2,408.6	2,365.9	2,309.8	2,327.8	2,308.7	2,329.2	2,411.8	2,478.3	2,551.4	2,596.7	2,571.5	2,646.2
1/22/2018	2,473.5	2,365.1	2,354.8	2,422.1	2,530.7	2,666.5	2,873.1	3,044.9	3,075.8	3,117.0	3,122.1	3,073.4
1/23/2018	2,502.0	2,512.5	2,495.3	2,532.4	2,597.8	2,752.8	2,971.5	3,155.0	3,212.3	3,204.8	3,210.8	3,170.8
1/24/2018	2,740.7	2,686.5	2,633.1	2,620.5	2,664.7	2,791.5	3,028.5	3,086.6	3,082.8	3,059.8	3,063.2	3,057.6
1/25/2018	2,791.3	2,738.1	2,695.5	2,738.7	2,792.0	2,941.3	3,156.2	3,349.7	3,317.3	3,300.7	3,305.2	3,300.7
1/26/2018	2,803.9	2,760.8	2,733.3	2,735.8	2,760.4	2,913.4	3,095.6	3,251.4	3,181.5	3,168.9	3,131.9	3,067.5
1/27/2018	2,496.9	2,438.0	2,432.7	2,433.5	2,443.2	2,506.4	2,563.3	2,633.7	2,706.4	2,758.9	2,755.8	2,807.9
1/28/2018	2,397.0	2,358.5	2,357.3	2,357.8	2,374.6	2,400.0	2,468.9	2,554.2	2,611.7	2,621.7	2,570.3	2,537.9

Indiana Michigan Power Company - Hourly Internal Load (MW)
Note: Hours refelct EST

DATE	HR1	HR2	HR3	HR4	HR5	HR6	HR7	HR8	HR9	HR10	HR11	HR12
1/29/2018	2,559.7	2,521.0	2,507.8	2,537.8	2,611.9	2,794.7	3,060.1	3,224.5	3,173.9	3,260.3	3,233.5	3,298.3
1/30/2018	2,865.2	2,827.9	2,807.2	2,822.7	2,853.2	2,988.4	3,246.6	3,406.7	3,373.8	3,389.8	3,328.1	3,251.8
1/31/2018	2,940.4	2,876.8	2,845.9	2,842.5	2,925.5	3,040.9	3,272.1	3,398.5	3,375.1	3,359.7	3,352.8	3,309.3
2/1/2018	2,725.3	2,658.5	2,641.4	2,651.1	2,735.6	2,868.5	3,096.9	3,212.2	3,207.9	3,243.2	3,237.5	3,246.0
2/2/2018	2,941.5	2,914.0	2,895.3	2,921.2	2,979.7	3,142.0	3,337.8	3,493.7	3,477.0	3,447.0	3,427.0	3,445.3
2/3/2018	2,913.8	2,853.2	2,807.7	2,807.8	2,832.8	2,866.2	2,941.0	3,006.8	3,083.4	3,059.0	3,047.2	3,087.2
2/4/2018	2,638.9	2,576.1	2,519.6	2,521.4	2,569.9	2,648.0	2,710.0	2,729.0	2,734.2	2,757.3	2,749.3	2,813.3
2/5/2018	2,781.2	2,792.1	2,819.5	2,846.1	2,933.1	3,091.7	3,341.6	3,488.3	3,523.4	3,483.4	3,467.6	3,411.1
2/6/2018	3,058.7	3,019.3	2,984.5	2,964.9	2,999.0	3,122.4	3,341.5	3,352.7	3,325.7	3,274.5	3,177.4	3,138.0
2/7/2018	2,916.4	2,944.4	2,959.5	2,976.5	3,059.9	3,184.4	3,347.3	3,493.1	3,459.5	3,453.2	3,450.1	3,393.5
2/8/2018	2,946.7	2,930.5	2,945.9	2,938.5	3,029.4	3,181.8	3,378.5	3,538.4	3,526.8	3,511.2	3,475.6	3,374.2
2/9/2018	2,998.2	2,929.1	2,896.1	2,901.9	2,932.1	3,041.1	3,199.1	3,317.2	3,324.9	3,351.5	3,336.4	3,310.6
2/10/2018	2,692.1	2,630.0	2,603.7	2,591.0	2,627.4	2,671.8	2,764.6	2,831.4	2,883.1	2,956.3	3,003.8	2,988.4
2/11/2018	2,691.5	2,618.6	2,589.7	2,589.8	2,622.6	2,657.7	2,692.9	2,762.1	2,815.4	2,846.5	2,861.6	2,843.1
2/12/2018	2,784.6	2,741.6	2,702.9	2,730.5	2,846.7	3,011.1	3,269.2	3,435.3	3,411.0	3,352.6	3,317.0	3,301.4
2/13/2018	2,897.8	2,885.6	2,855.0	2,853.3	2,817.1	3,063.4	3,305.0	3,409.3	3,409.1	3,356.9	3,304.3	3,281.3
2/14/2018	2,759.7	2,715.0	2,708.3	2,692.8	2,773.9	2,943.0	3,184.8	3,291.8	3,288.7	3,178.1	3,170.3	3,139.1
2/15/2018	2,548.9	2,475.4	2,465.9	2,461.3	2,527.5	2,647.7	2,821.6	2,965.3	3,002.2	2,998.8	3,014.3	3,051.4
2/16/2018	2,509.7	2,495.9	2,488.8	2,522.7	2,590.4	2,727.9	2,945.8	3,119.0	3,117.4	3,132.8	3,139.9	3,064.8
2/17/2018	2,669.8	2,616.3	2,603.5	2,585.2	2,620.5	2,695.0	2,693.6	2,792.1	2,874.7	2,931.3	2,957.1	2,970.9
2/18/2018	2,451.4	2,419.0	2,396.2	2,376.4	2,401.8	2,436.0	2,471.3	2,555.5	2,616.2	2,641.6	2,633.1	2,643.4
2/19/2018	2,567.4	2,513.4	2,509.2	2,542.4	2,596.3	2,734.9	2,915.1	3,051.0	3,071.8	3,110.2	3,136.6	3,111.6
2/20/2018	2,489.4	2,428.7	2,323.4	2,359.5	2,421.4	2,549.0	2,738.3	2,900.6	2,929.8	2,955.0	2,993.0	2,928.6
2/21/2018	2,419.3	2,375.7	2,378.7	2,390.4	2,408.5	2,567.4	2,770.2	2,816.2	2,842.7	2,880.7	2,901.0	2,888.0
2/22/2018	2,697.4	2,645.2	2,619.4	2,652.4	2,691.9	2,849.3	3,065.1	3,180.1	2,938.0	2,966.9	3,008.3	2,977.5
2/23/2018	2,651.7	2,599.9	2,451.6	2,342.7	2,393.1	2,523.6	2,717.8	2,844.4	2,824.9	2,827.6	2,825.4	2,755.3
2/24/2018	2,197.9	2,138.8	2,141.8	2,158.4	2,199.3	2,348.2	2,411.8	2,559.6	2,612.3	2,662.9	2,673.2	2,680.4
2/25/2018	2,297.5	2,234.5	2,159.4	2,131.8	2,179.7	2,224.5	2,315.9	2,400.7	2,462.8	2,557.5	2,549.5	2,557.9

Indiana Michigan Power Company - Hourly Internal Load (MW)
Note: Hours refelct EST

DATE	HR1	HR2	HR3	HR4	HR5	HR6	HR7	HR8	HR9	HR10	HR11	HR12
2/26/2018	2,381.2	2,497.3	2,500.6	2,548.9	2,617.6	2,779.7	3,005.3	3,117.1	3,071.4	3,086.3	3,039.6	2,959.5
2/27/2018	2,584.5	2,501.5	2,472.7	2,406.1	2,626.6	2,769.6	2,985.5	3,049.8	3,051.5	3,013.5	3,017.2	2,930.4
2/28/2018	2,472.9	2,420.5	2,384.8	2,424.1	2,487.1	2,645.5	2,859.8	2,988.8	2,995.9	2,970.8	2,965.3	2,961.5
3/1/2018	2,497.0	2,454.2	2,299.6	2,392.7	2,517.1	2,671.3	2,905.7	3,040.4	3,063.5	3,126.5	3,149.1	3,150.1
3/2/2018	2,651.4	2,607.2	2,598.8	2,612.8	2,664.6	2,812.6	3,042.2	3,135.8	3,080.3	3,057.0	3,038.8	2,993.2
3/3/2018	2,582.8	2,556.4	2,538.8	2,516.2	2,566.7	2,617.1	2,691.5	2,714.2	2,750.3	2,729.9	2,781.2	2,710.0
3/4/2018	2,457.0	2,383.9	2,388.5	2,390.1	2,391.7	2,393.7	2,452.0	2,511.5	2,608.5	2,655.8	2,617.2	2,614.0
3/5/2018	2,565.5	2,569.0	2,565.6	2,583.2	2,655.8	2,810.9	3,072.7	3,126.4	3,159.4	3,169.7	3,168.2	3,169.3
3/6/2018	2,645.3	2,617.9	2,619.7	2,582.7	2,591.6	2,748.5	2,946.2	2,950.5	2,961.6	2,956.7	2,882.4	2,864.6
3/7/2018	2,657.6	2,598.7	2,620.6	2,626.0	2,728.9	2,864.7	3,108.3	3,217.0	3,232.8	3,235.7	3,247.9	3,224.8
3/8/2018	2,770.0	2,723.1	2,679.7	2,689.6	2,724.1	2,880.5	3,150.5	3,280.8	3,268.2	3,286.0	3,293.6	3,231.8
3/9/2018	2,800.2	2,746.9	2,704.5	2,636.8	2,793.5	2,948.7	3,137.8	3,226.1	3,217.1	3,195.3	3,127.9	3,140.8
3/10/2018	2,676.9	2,618.5	2,626.3	2,605.8	2,639.7	2,707.6	2,786.4	2,812.8	2,864.3	2,849.8	2,832.3	2,763.9
3/11/2018	2,480.9	2,467.5	2,425.1	2,440.1	2,468.9	2,548.9	2,607.5	2,617.4	2,655.3	2,668.1	2,614.1	2,617.3
3/12/2018	2,587.6	2,556.4	2,588.4	2,675.1	2,786.5	3,053.4	3,250.5	3,263.3	3,288.2	3,300.7	3,242.2	3,233.3
3/13/2018	2,684.2	2,654.6	2,684.0	2,722.0	2,889.4	3,105.2	3,201.8	3,192.3	3,169.4	3,150.5	3,147.7	3,145.1
3/14/2018	2,769.6	2,691.2	2,711.5	2,719.6	2,873.9	3,114.1	3,265.1	3,213.5	3,162.9	3,106.5	3,079.7	3,066.0
3/15/2018	2,648.9	2,624.0	2,655.1	2,725.1	2,868.9	3,063.8	3,157.9	3,103.2	3,146.4	3,154.2	3,123.9	3,067.0
3/16/2018	2,677.7	2,647.3	2,686.0	2,741.3	2,864.6	3,015.6	3,187.5	3,193.3	3,156.3	3,172.9	3,092.8	3,065.5
3/17/2018	2,564.5	2,512.8	2,536.7	2,562.2	2,605.9	2,667.5	2,774.0	2,823.3	2,870.9	2,888.3	2,843.7	2,754.0
3/18/2018	2,425.2	2,412.8	2,423.0	2,420.9	2,441.2	2,421.5	2,558.8	2,610.6	2,619.4	2,508.8	2,556.9	2,526.5
3/19/2018	2,424.6	2,434.3	2,482.6	2,520.5	2,726.8	2,971.3	3,112.8	3,150.8	3,135.2	3,091.1	3,086.9	3,050.5
3/20/2018	2,664.1	2,646.3	2,673.6	2,738.3	2,907.5	3,143.3	3,299.9	3,272.2	3,236.6	3,213.2	3,155.6	3,074.5
3/21/2018	2,675.8	2,662.5	2,677.0	2,734.9	2,886.9	3,025.8	3,084.7	3,040.7	3,029.6	3,033.4	2,972.1	2,942.4
3/22/2018	2,642.1	2,646.6	2,674.6	2,737.2	2,889.3	3,091.0	3,254.3	3,236.9	3,202.8	3,158.9	3,122.0	3,111.2
3/23/2018	2,607.0	2,600.0	2,588.6	2,635.8	2,789.5	3,029.2	3,096.7	3,114.5	3,110.8	3,065.7	3,022.9	3,017.2
3/24/2018	2,510.4	2,476.6	2,492.9	2,537.3	2,600.0	2,711.6	2,760.9	2,858.1	2,907.5	2,912.0	2,887.8	2,830.6
3/25/2018	2,488.4	2,454.1	2,481.9	2,498.8	2,502.5	2,584.1	2,687.9	2,745.8	2,773.2	2,749.2	2,744.2	2,699.2

Indiana Michigan Power Company - Hourly Internal Load (MW)
Note: Hours refelct EST

DATE	HR1	HR2	HR3	HR4	HR5	HR6	HR7	HR8	HR9	HR10	HR11	HR12
3/26/2018	2,568.4	2,517.2	2,541.1	2,620.3	2,771.5	2,986.5	3,115.0	3,048.6	3,037.6	3,051.1	3,010.7	2,993.5
3/27/2018	2,466.3	2,489.5	2,479.3	2,547.4	2,656.1	2,870.4	3,008.1	3,083.5	2,961.6	3,042.4	3,038.1	3,067.1
3/28/2018	2,404.9	2,422.8	2,432.4	2,496.6	2,645.0	2,837.5	2,988.8	2,990.1	3,034.4	3,065.0	3,047.3	3,003.5
3/29/2018	2,440.5	2,387.5	2,412.3	2,487.4	2,605.3	2,784.9	2,938.8	2,953.1	2,924.2	3,017.4	3,032.6	3,040.7
3/30/2018	2,391.9	2,346.8	2,320.8	2,377.5	2,467.9	2,590.4	2,684.2	2,731.4	2,761.2	2,757.1	2,740.9	2,686.6
3/31/2018	2,261.9	2,287.8	2,280.7	2,305.1	2,370.8	2,427.0	2,473.9	2,539.2	2,591.2	2,620.6	2,655.3	2,618.3
4/1/2018	2,196.2	2,195.6	2,194.3	2,200.8	2,255.2	2,299.2	2,370.6	2,397.1	2,427.7	2,423.7	2,391.0	2,364.1
4/2/2018	2,408.6	2,385.4	2,448.6	2,527.8	2,686.5	2,848.8	2,976.9	2,976.8	2,972.6	2,976.0	2,933.6	2,902.3
4/3/2018	2,497.6	2,461.1	2,503.3	2,568.7	2,714.0	2,891.2	3,008.7	3,013.8	3,023.7	3,070.1	3,016.4	3,035.6
4/4/2018	2,387.9	2,430.1	2,468.7	2,526.4	2,716.4	2,949.5	3,087.1	3,140.5	3,123.2	3,158.6	3,186.9	3,150.9
4/5/2018	2,635.3	2,630.5	2,637.7	2,687.4	2,832.1	3,029.4	3,137.7	3,087.5	3,093.1	3,069.0	3,036.5	2,997.6
4/6/2018	2,557.6	2,508.6	2,493.5	2,542.7	2,672.6	2,857.1	2,940.2	2,974.9	3,023.9	3,022.0	3,002.0	2,989.6
4/7/2018	2,567.8	2,547.1	2,488.8	2,546.8	2,646.9	2,743.3	2,761.9	2,800.2	2,837.1	2,810.0	2,786.9	2,758.4
4/8/2018	2,482.6	2,471.7	2,470.4	2,491.1	2,538.1	2,546.2	2,619.1	2,672.9	2,651.4	2,657.0	2,516.0	2,602.2
4/9/2018	2,542.9	2,571.9	2,579.5	2,642.3	2,786.2	2,999.1	3,189.3	3,161.1	3,144.3	3,143.4	3,112.5	3,098.6
4/10/2018	2,532.3	2,557.4	2,581.6	2,659.1	2,820.0	3,057.4	3,141.2	3,115.1	3,071.1	3,082.2	3,057.9	3,021.3
4/11/2018	2,553.7	2,522.3	2,539.8	2,549.3	2,722.7	2,865.3	2,916.9	2,911.0	2,878.5	2,849.7	2,791.5	2,753.7
4/12/2018	2,352.3	2,365.9	2,345.6	2,440.9	2,566.1	2,803.1	2,812.4	2,836.9	2,766.7	2,848.4	2,839.7	2,875.7
4/13/2018	2,260.5	2,234.3	2,242.8	2,284.7	2,444.9	2,599.9	2,686.2	2,733.1	2,798.5	2,816.6	2,833.1	2,818.5
4/14/2018	2,118.7	2,239.8	2,199.6	2,204.9	2,301.9	2,392.6	2,467.1	2,528.1	2,622.7	2,701.1	2,667.3	2,638.6
4/15/2018	2,453.8	2,407.9	2,371.9	2,368.8	2,408.3	2,500.0	2,579.3	2,635.0	2,683.0	2,733.0	2,733.9	2,632.0
4/16/2018	2,405.6	2,392.8	2,459.4	2,528.6	2,683.1	2,955.7	3,107.2	3,150.7	3,216.5	3,229.8	3,235.8	3,247.5
4/17/2018	2,650.5	2,638.6	2,646.6	2,708.3	2,868.8	3,091.6	3,202.1	3,211.2	3,241.4	3,264.3	3,245.1	3,211.5
4/18/2018	2,659.4	2,646.9	2,598.6	2,702.3	2,877.4	3,097.4	3,161.4	3,138.3	3,154.6	3,182.3	3,124.3	3,056.2
4/19/2018	2,578.4	2,569.9	2,573.5	2,593.2	2,756.6	2,960.6	3,058.6	3,060.9	3,048.7	3,025.5	2,971.1	2,972.6
4/20/2018	2,534.6	2,495.9	2,478.6	2,597.5	2,752.4	2,966.0	3,032.1	3,029.8	2,979.4	2,947.3	2,897.6	2,871.5
4/21/2018	2,272.1	2,293.3	2,292.5	2,363.0	2,430.8	2,489.2	2,533.4	2,542.2	2,640.7	2,512.1	2,548.6	2,448.5
4/22/2018	2,114.8	2,104.6	2,104.7	2,037.1	2,129.4	2,145.5	2,248.1	2,313.0	2,367.0	2,352.2	2,339.6	2,349.8

Indiana Michigan Power Company - Hourly Internal Load (MW)
Note: Hours refelct EST

DATE	HR1	HR2	HR3	HR4	HR5	HR6	HR7	HR8	HR9	HR10	HR11	HR12
4/23/2018	2,205.4	2,202.9	2,246.2	2,320.8	2,535.8	2,784.1	2,894.5	2,890.3	2,865.5	2,831.2	2,840.0	2,845.2
4/24/2018	2,327.9	2,271.0	2,306.8	2,379.5	2,484.2	2,772.6	2,813.2	2,874.9	2,858.4	2,925.9	2,879.1	2,860.2
4/25/2018	2,352.1	2,328.7	2,359.4	2,403.5	2,576.1	2,803.2	2,897.8	2,930.4	2,884.1	2,863.9	2,820.2	2,766.5
4/26/2018	2,263.0	2,286.4	2,336.4	2,416.4	2,546.2	2,748.1	2,843.6	2,857.0	2,841.8	2,817.8	2,805.4	2,815.0
4/27/2018	2,251.2	2,257.1	2,263.3	2,360.5	2,540.8	2,744.1	2,776.5	2,835.2	2,827.2	2,874.5	2,851.0	2,815.8
4/28/2018	2,252.9	2,185.2	2,179.5	2,208.2	2,254.6	2,348.4	2,412.1	2,490.7	2,570.5	2,595.4	2,561.2	2,539.5
4/29/2018	2,255.2	2,219.5	2,190.4	2,201.3	2,259.1	2,309.9	2,352.4	2,386.6	2,374.7	2,303.6	2,313.1	2,335.2
4/30/2018	2,278.0	2,269.1	2,246.7	2,353.2	2,558.1	2,704.2	2,839.6	2,884.8	2,852.7	2,854.5	2,833.2	2,830.7
5/1/2018	2,205.9	2,168.7	2,166.5	2,206.4	2,372.8	2,518.2	2,558.3	2,592.1	2,609.6	2,651.8	2,669.9	2,700.4
5/2/2018	2,222.7	2,183.5	2,224.3	2,282.1	2,436.6	2,642.4	2,747.9	2,780.9	2,870.3	2,952.1	3,003.6	3,043.7
5/3/2018	2,417.6	2,360.1	2,363.4	2,396.8	2,530.4	2,785.0	2,852.1	2,848.6	2,984.8	2,998.6	3,001.5	3,040.9
5/4/2018	2,407.2	2,354.8	2,346.3	2,385.7	2,527.5	2,752.5	2,862.4	2,939.4	2,890.2	3,007.2	2,963.7	3,003.1
5/5/2018	2,113.1	2,014.6	1,956.7	2,023.4	2,094.2	2,148.2	2,226.0	2,292.8	2,420.1	2,440.1	2,479.1	2,477.9
5/6/2018	2,121.3	2,038.8	1,994.4	1,989.9	1,988.2	2,043.3	2,094.4	2,201.8	2,284.5	2,359.6	2,415.3	2,463.4
5/7/2018	2,191.2	2,158.5	2,169.7	2,256.2	2,416.0	2,633.1	2,749.6	2,788.9	2,883.7	2,899.9	2,845.0	2,867.8
5/8/2018	2,238.1	2,261.9	2,274.9	2,327.1	2,458.8	2,639.5	2,774.9	2,808.6	2,846.4	2,881.9	2,932.1	2,981.4
5/9/2018	2,347.1	2,273.3	2,277.9	2,329.7	2,465.8	2,639.8	2,762.1	2,855.6	2,820.2	2,901.9	2,982.6	3,019.9
5/10/2018	2,424.2	2,309.3	2,297.3	2,363.5	2,450.2	2,699.9	2,776.6	2,836.4	2,893.2	2,978.9	2,986.9	2,985.0
5/11/2018	2,283.7	2,169.5	2,139.0	2,194.8	2,322.7	2,551.6	2,677.2	2,737.2	2,706.3	2,759.8	2,810.8	2,782.6
5/12/2018	2,132.5	2,090.4	2,017.9	2,081.7	2,099.8	2,188.0	2,251.2	2,354.3	2,405.6	2,485.6	2,406.0	2,447.2
5/13/2018	1,980.1	1,975.8	1,958.6	1,932.0	1,955.1	1,986.1	2,027.3	2,131.4	2,201.6	2,227.1	2,234.0	2,271.1
5/14/2018	2,226.3	2,206.8	2,189.6	2,268.4	2,447.0	2,668.7	2,786.5	2,926.1	2,999.0	2,984.6	2,964.0	3,008.6
5/15/2018	2,442.1	2,413.4	2,382.7	2,382.2	2,516.7	2,654.9	2,822.2	2,871.6	2,964.2	3,045.2	3,066.3	3,090.4
5/16/2018	2,305.4	2,253.5	2,200.1	2,217.1	2,293.1	2,486.5	2,574.7	2,651.2	2,687.3	2,711.1	2,761.3	2,801.5
5/17/2018	2,272.0	2,248.0	2,227.2	2,280.5	2,452.7	2,634.0	2,790.2	2,834.0	2,881.7	2,865.3	2,900.5	3,102.3
5/18/2018	2,357.4	2,272.2	2,292.6	2,298.4	2,432.4	2,600.7	2,735.5	2,770.7	2,831.9	2,859.0	2,863.2	2,886.6
5/19/2018	2,215.4	2,180.5	2,126.3	2,153.0	2,207.5	2,265.0	2,227.5	2,397.8	2,484.3	2,572.9	2,488.6	2,602.1
5/20/2018	2,080.0	2,005.8	1,986.7	1,950.0	2,033.8	2,011.3	2,057.2	2,064.6	2,219.5	2,348.8	2,377.0	2,466.5

Indiana Michigan Power Company - Hourly Internal Load (MW)
Note: Hours refelct EST

DATE	HR1	HR2	HR3	HR4	HR5	HR6	HR7	HR8	HR9	HR10	HR11	HR12
5/21/2018	2,257.3	2,186.1	2,194.8	2,215.1	2,390.3	2,636.6	2,738.3	2,788.7	2,732.0	2,815.6	2,941.4	2,987.1
5/22/2018	2,333.6	2,274.6	2,289.3	2,325.5	2,513.6	2,660.0	2,829.1	2,900.8	2,930.5	2,963.7	3,017.1	3,084.9
5/23/2018	2,333.8	2,273.2	2,234.9	2,263.6	2,445.5	2,603.4	2,753.8	2,883.5	2,936.5	2,938.2	3,018.2	3,064.8
5/24/2018	2,369.1	2,296.4	2,282.3	2,354.2	2,481.6	2,652.3	2,797.9	2,876.6	2,975.5	2,976.2	2,994.7	3,110.4
5/25/2018	2,404.3	2,337.5	2,271.3	2,339.3	2,425.0	2,580.9	2,696.7	2,819.3	2,965.4	3,059.0	3,140.7	3,231.0
5/26/2018	2,400.4	2,362.9	2,295.2	2,305.6	2,320.8	2,285.9	2,310.5	2,496.6	2,627.8	2,713.6	2,785.1	2,931.7
5/27/2018	2,291.2	2,231.7	2,192.6	2,069.5	2,072.2	2,050.1	2,151.9	2,345.3	2,543.0	2,751.5	2,934.7	3,085.9
5/28/2018	2,407.3	2,290.5	2,219.0	2,157.0	2,165.4	2,157.6	2,283.1	2,435.8	2,672.1	2,821.5	3,035.7	3,204.3
5/29/2018	2,689.5	2,601.5	2,548.5	2,573.8	2,683.5	2,793.1	3,047.9	3,240.6	3,424.4	3,624.1	3,797.7	3,927.9
5/30/2018	2,834.9	2,766.4	2,715.3	2,726.0	2,838.6	3,069.7	3,266.1	3,422.9	3,529.2	3,671.5	3,790.2	3,918.2
5/31/2018	2,735.7	2,682.0	2,663.5	2,697.1	2,785.6	2,985.8	3,031.6	3,249.7	3,379.8	3,580.3	3,707.7	3,841.2
6/1/2018	2,767.4	2,614.5	2,568.1	2,598.3	2,723.4	2,840.2	2,937.3	3,147.0	3,290.5	3,422.0	3,585.4	3,658.9
6/2/2018	2,478.9	2,384.6	2,296.7	2,308.6	2,405.5	2,389.2	2,395.5	2,552.4	2,631.0	2,719.6	2,728.3	2,747.3
6/3/2018	2,373.6	2,248.0	2,254.4	2,247.3	2,153.6	2,219.7	2,290.9	2,404.9	2,545.6	2,595.0	2,701.0	2,748.5
6/4/2018	2,282.1	2,237.7	2,245.8	2,284.0	2,441.2	2,597.8	2,733.0	2,819.2	2,842.8	2,894.2	2,979.0	3,000.5
6/5/2018	2,430.5	2,349.3	2,295.0	2,382.5	2,449.1	2,668.6	2,710.4	2,756.3	2,917.7	2,953.8	2,964.0	2,996.2
6/6/2018	2,288.4	2,241.7	2,228.7	2,218.1	2,294.7	2,417.4	2,507.4	2,574.1	2,613.7	2,656.1	2,696.1	2,733.5
6/7/2018	2,311.5	2,328.7	2,315.6	2,336.4	2,521.4	2,652.5	2,753.7	2,816.0	2,977.0	3,046.3	3,190.9	3,262.7
6/8/2018	2,578.3	2,514.6	2,486.4	2,482.1	2,584.0	2,735.1	2,908.2	3,014.0	3,078.8	3,189.7	3,288.9	3,202.8
6/9/2018	2,512.0	2,451.5	2,337.1	2,287.2	2,336.1	2,355.9	2,437.4	2,567.5	2,700.6	2,836.6	2,908.8	2,977.0
6/10/2018	2,284.6	2,245.9	2,194.7	2,169.4	2,145.3	2,175.6	2,252.2	2,302.9	2,373.7	2,517.2	2,590.8	2,593.0
6/11/2018	2,350.6	2,294.2	2,313.0	2,389.7	2,468.1	2,686.7	2,827.0	2,930.5	2,964.0	2,972.8	2,992.3	3,038.2
6/12/2018	2,477.1	2,393.9	2,391.1	2,395.8	2,423.4	2,684.5	2,816.4	2,906.8	2,954.1	3,025.6	3,096.2	3,164.6
6/13/2018	2,583.5	2,490.9	2,432.6	2,534.2	2,680.3	2,809.5	2,944.6	3,097.6	3,207.9	3,349.0	3,416.8	3,379.9
6/14/2018	2,308.1	2,337.8	2,299.1	2,264.9	2,501.5	2,626.8	2,751.1	2,880.1	2,987.3	3,082.5	3,199.6	3,280.5
6/15/2018	2,443.9	2,392.1	2,368.0	2,442.2	2,539.0	2,650.1	2,808.8	2,944.1	2,988.6	3,186.5	3,263.3	3,423.4
6/16/2018	2,514.4	2,464.6	2,400.0	2,404.9	2,427.5	2,467.2	2,526.1	2,663.7	2,843.7	3,002.8	3,123.7	3,216.5
6/17/2018	2,745.4	2,636.3	2,550.3	2,472.1	2,454.9	2,367.0	2,530.3	2,777.4	3,044.7	3,222.7	3,405.9	3,554.9

Indiana Michigan Power Company - Hourly Internal Load (MW)
Note: Hours refelct EST

DATE	HR1	HR2	HR3	HR4	HR5	HR6	HR7	HR8	HR9	HR10	HR11	HR12
6/18/2018	3,024.5	2,944.4	2,941.9	2,900.0	3,048.6	3,192.3	3,402.4	3,583.5	3,802.2	4,020.5	4,096.6	4,266.4
6/19/2018	2,952.0	2,877.3	2,803.6	2,812.6	2,929.3	3,068.0	3,181.1	3,347.6	3,468.9	3,626.4	3,668.7	3,832.4
6/20/2018	2,644.0	2,629.8	2,604.4	2,650.6	2,775.5	2,876.0	3,016.8	3,150.1	3,217.4	3,204.8	3,303.6	3,330.6
6/21/2018	2,591.0	2,471.4	2,472.1	2,507.6	2,592.9	2,670.0	2,774.6	2,827.5	2,876.4	2,931.7	2,971.0	2,995.0
6/22/2018	2,277.4	2,237.3	2,353.3	2,439.8	2,549.1	2,704.3	2,779.8	2,893.2	2,957.6	2,966.1	3,012.6	3,061.2
6/23/2018	2,366.6	2,278.4	2,249.3	2,236.0	2,318.3	2,344.9	2,416.0	2,471.2	2,492.3	2,548.0	2,627.7	2,713.3
6/24/2018	2,240.5	2,153.6	2,096.8	2,111.6	2,126.2	2,094.4	2,175.8	2,314.2	2,455.2	2,598.8	2,730.5	2,815.2
6/25/2018	2,386.1	2,323.3	2,318.4	2,352.5	2,495.2	2,673.3	2,800.4	2,887.5	2,913.7	3,019.3	3,104.8	3,274.8
6/26/2018	2,508.7	2,422.4	2,347.4	2,332.4	2,489.4	2,672.1	2,788.5	2,876.3	2,871.0	3,121.1	3,190.9	3,285.3
6/27/2018	2,634.8	2,555.7	2,510.9	2,546.7	2,667.9	2,835.5	2,979.6	3,084.9	3,127.9	3,156.0	3,183.9	3,197.2
6/28/2018	2,509.0	2,452.5	2,444.7	2,459.2	2,572.9	2,718.1	2,865.0	3,048.9	3,082.1	3,271.9	3,368.8	3,494.4
6/29/2018	2,737.9	2,585.9	2,555.8	2,572.9	2,654.2	2,807.3	2,979.4	3,116.9	3,339.9	3,513.2	3,598.5	3,708.4
6/30/2018	2,936.8	2,824.6	2,751.2	2,714.0	2,711.7	2,666.0	2,791.2	3,044.5	3,262.8	3,431.3	3,464.5	3,693.2
7/1/2018	2,845.3	2,694.2	2,573.3	2,513.7	2,502.9	2,410.0	2,595.3	2,847.2	3,108.3	3,249.8	3,450.4	3,547.4
7/2/2018	2,943.3	2,870.4	2,785.2	2,791.1	2,888.3	2,991.8	3,112.0	3,286.0	3,440.7	3,537.0	3,573.7	3,759.0
7/3/2018	2,740.2	2,610.7	2,603.7	2,558.3	2,678.3	2,762.6	2,939.9	3,116.0	3,349.3	3,553.0	3,698.9	3,905.9
7/4/2018	2,845.0	2,698.4	2,616.4	2,577.4	2,488.4	2,406.4	2,504.5	2,771.4	3,027.9	3,270.0	3,416.7	3,578.9
7/5/2018	2,869.0	2,701.8	2,619.7	2,662.0	2,777.9	2,854.1	3,074.1	3,249.1	3,343.6	3,610.9	3,790.5	3,915.1
7/6/2018	2,715.2	2,570.4	2,557.8	2,531.1	2,588.5	2,637.2	2,703.5	2,901.3	2,982.4	3,067.2	3,137.3	3,211.5
7/7/2018	2,316.6	2,224.1	2,182.1	2,131.1	2,159.1	2,157.0	2,252.5	2,350.9	2,471.2	2,601.1	2,668.5	2,673.1
7/8/2018	2,243.4	2,178.9	2,129.7	2,097.9	2,086.0	2,096.8	2,131.0	2,268.9	2,396.7	2,563.2	2,689.7	2,760.7
7/9/2018	2,498.3	2,442.8	2,411.3	2,507.4	2,594.5	2,686.2	2,862.3	3,069.2	3,266.5	3,402.2	3,544.1	3,779.0
7/10/2018	2,913.3	2,823.7	2,787.9	2,790.1	2,828.1	2,979.2	3,212.0	3,398.4	3,626.8	3,841.8	4,009.6	4,155.1
7/11/2018	2,712.2	2,640.3	2,555.9	2,571.1	2,657.5	2,777.2	2,785.0	2,916.8	3,048.6	3,177.1	3,277.5	3,394.3
7/12/2018	2,529.7	2,444.9	2,522.8	2,567.6	2,661.9	2,806.3	2,912.1	3,027.0	3,085.2	3,281.2	3,430.9	3,585.5
7/13/2018	2,720.0	2,643.2	2,595.9	2,615.5	2,709.1	2,841.6	2,895.6	3,163.0	3,314.1	3,470.1	3,591.2	3,708.8
7/14/2018	2,779.2	2,707.4	2,599.7	2,641.5	2,600.6	2,587.6	2,646.3	2,843.6	3,004.8	3,126.0	3,325.1	3,368.8
7/15/2018	2,654.3	2,583.3	2,511.8	2,473.5	2,498.6	2,446.0	2,555.5	2,712.8	2,890.9	3,104.3	3,303.9	3,472.8

Indiana Michigan Power Company - Hourly Internal Load (MW)
Note: Hours refelct EST

DATE	HR1	HR2	HR3	HR4	HR5	HR6	HR7	HR8	HR9	HR10	HR11	HR12
7/16/2018	2,880.0	2,768.8	2,740.0	2,812.1	2,926.1	3,077.3	3,288.4	3,393.0	3,495.2	3,719.7	3,841.4	4,033.3
7/17/2018	2,861.2	2,713.9	2,632.3	2,695.0	2,797.6	2,843.8	2,993.8	3,208.3	3,381.3	3,491.7	3,599.5	3,731.3
7/18/2018	2,535.6	2,451.0	2,424.4	2,404.4	2,572.4	2,702.6	2,862.5	2,966.8	3,077.4	3,224.7	3,331.7	3,401.3
7/19/2018	2,581.5	2,527.3	2,483.3	2,517.9	2,639.4	2,756.8	2,854.4	2,993.6	3,133.1	3,315.4	3,416.4	3,493.6
7/20/2018	2,682.7	2,601.5	2,588.4	2,623.9	2,739.8	2,859.9	2,983.6	3,097.3	3,166.6	3,254.7	3,373.0	3,442.4
7/21/2018	2,468.3	2,326.1	2,333.8	2,355.1	2,386.2	2,343.7	2,491.0	2,629.9	2,636.0	2,762.0	2,760.0	2,781.9
7/22/2018	2,373.6	2,315.7	2,294.3	2,254.6	2,295.6	2,292.6	2,362.9	2,473.7	2,553.1	2,669.6	2,808.2	2,873.8
7/23/2018	2,397.1	2,383.9	2,361.9	2,440.7	2,531.9	2,679.8	2,820.0	2,954.0	3,076.2	3,176.3	3,216.2	3,303.2
7/24/2018	2,575.0	2,481.1	2,421.0	2,492.8	2,612.4	2,732.5	2,780.8	2,873.5	2,964.7	3,023.4	3,023.8	3,050.1
7/25/2018	2,586.8	2,529.8	2,501.4	2,544.8	2,648.0	2,831.2	2,977.1	3,131.2	3,259.3	3,390.2	3,516.3	3,640.1
7/26/2018	2,636.5	2,515.1	2,525.2	2,548.2	2,578.4	2,730.6	2,789.5	3,021.1	3,135.9	3,150.1	3,346.5	3,432.1
7/27/2018	2,525.6	2,476.4	2,408.3	2,464.7	2,594.9	2,720.6	2,816.4	2,963.2	3,071.0	3,144.9	3,184.3	3,213.7
7/28/2018	2,290.9	2,244.7	2,233.9	2,222.5	2,307.9	2,270.0	2,345.4	2,413.1	2,528.6	2,603.2	2,773.2	2,808.6
7/29/2018	2,250.8	2,154.8	2,100.1	2,095.9	2,135.0	2,155.7	2,080.4	2,252.0	2,398.5	2,515.6	2,624.3	2,687.9
7/30/2018	2,426.4	2,352.9	2,359.0	2,413.2	2,529.5	2,701.7	2,762.1	2,907.1	2,949.1	3,082.5	3,000.5	3,097.8
7/31/2018	2,370.9	2,367.1	2,407.8	2,529.0	2,677.5	2,867.3	2,984.4	2,998.2	3,002.4	3,097.8	3,142.8	3,166.5
8/1/2018	2,502.5	2,448.5	2,443.5	2,484.8	2,628.2	2,746.9	2,878.8	2,981.5	3,100.4	3,148.7	3,262.5	3,375.9
8/2/2018	2,535.4	2,516.6	2,435.1	2,480.3	2,647.4	2,830.3	2,907.2	3,032.3	3,114.5	3,265.2	3,439.3	3,513.8
8/3/2018	2,625.4	2,514.2	2,484.7	2,565.9	2,636.0	2,767.0	2,924.8	3,059.5	3,209.1	3,377.3	3,462.9	3,582.0
8/4/2018	2,520.2	2,442.8	2,392.3	2,409.9	2,451.1	2,444.1	2,489.6	2,656.3	2,836.5	3,012.4	3,233.6	3,403.8
8/5/2018	2,734.1	2,634.9	2,504.1	2,458.8	2,439.2	2,446.3	2,519.7	2,662.8	2,902.1	3,075.4	3,240.4	3,421.5
8/6/2018	2,972.5	2,779.0	2,764.1	2,778.7	2,912.7	3,078.7	3,226.8	3,393.5	3,523.8	3,683.1	3,840.5	3,973.3
8/7/2018	2,837.5	2,731.6	2,692.8	2,703.6	2,847.8	2,941.5	3,016.7	3,199.1	3,353.6	3,392.8	3,601.5	3,689.6
8/8/2018	2,753.7	2,682.9	2,637.0	2,652.9	2,778.3	2,907.3	2,950.7	3,042.6	3,105.3	3,226.0	3,346.1	3,437.5
8/9/2018	2,587.0	2,533.1	2,516.8	2,552.7	2,645.3	2,798.0	2,869.0	3,037.2	3,174.4	3,329.8	3,469.9	3,626.0
8/10/2018	2,724.7	2,560.7	2,570.8	2,684.9	2,756.5	2,965.4	3,051.3	3,168.3	3,264.8	3,323.4	3,453.0	3,535.0
8/11/2018	2,641.3	2,537.6	2,473.7	2,442.4	2,462.1	2,452.4	2,548.0	2,666.5	2,787.3	2,937.8	3,076.6	3,157.7
8/12/2018	2,298.9	2,286.3	2,302.6	2,223.3	2,196.3	2,168.4	2,215.2	2,407.0	2,583.2	2,766.2	2,961.2	3,061.3

Indiana Michigan Power Company - Hourly Internal Load (MW)
Note: Hours refelct EST

DATE	HR1	HR2	HR3	HR4	HR5	HR6	HR7	HR8	HR9	HR10	HR11	HR12
8/13/2018	2,620.7	2,569.0	2,445.2	2,504.7	2,690.3	2,881.4	2,994.4	3,121.2	3,252.3	3,450.3	3,584.1	3,627.6
8/14/2018	2,708.5	2,605.3	2,527.1	2,565.6	2,681.5	2,914.6	2,961.9	3,056.3	3,228.1	3,355.6	3,557.4	3,720.4
8/15/2018	2,690.0	2,643.0	2,609.6	2,590.4	2,778.9	2,993.1	3,047.6	3,168.4	3,224.4	3,311.7	3,468.4	3,624.9
8/16/2018	2,710.2	2,648.3	2,627.9	2,627.8	2,794.2	3,073.2	3,137.3	3,195.2	3,237.4	3,250.6	3,369.2	3,445.8
8/17/2018	2,667.8	2,629.4	2,599.7	2,681.1	2,888.8	3,075.3	3,204.3	3,231.0	3,234.4	3,355.6	3,429.6	3,527.0
8/18/2018	2,563.1	2,475.3	2,418.6	2,410.7	2,471.9	2,512.2	2,505.5	2,654.0	2,792.6	2,895.3	3,017.3	3,138.1
8/19/2018	2,474.7	2,360.6	2,289.6	2,242.2	2,295.5	2,318.4	2,319.2	2,437.0	2,581.9	2,732.9	2,875.9	3,002.7
8/20/2018	2,596.6	2,484.4	2,426.0	2,438.4	2,644.0	2,869.5	2,968.5	2,989.2	3,098.2	3,305.7	3,375.2	3,465.0
8/21/2018	2,670.5	2,618.9	2,594.0	2,621.3	2,733.0	2,877.2	2,986.6	2,988.7	3,047.2	3,122.0	3,188.6	3,231.5
8/22/2018	2,510.7	2,351.6	2,313.4	2,374.8	2,546.7	2,728.2	2,803.3	2,905.7	2,941.3	3,046.8	3,089.1	3,131.6
8/23/2018	2,314.5	2,273.5	2,277.3	2,348.5	2,464.4	2,688.9	2,748.3	2,836.7	2,823.7	2,915.8	2,974.9	3,047.3
8/24/2018	2,411.2	2,281.8	2,324.0	2,360.4	2,477.4	2,646.3	2,797.6	2,864.9	2,865.4	2,999.5	3,082.7	3,126.6
8/25/2018	2,400.6	2,366.9	2,360.3	2,382.2	2,436.3	2,480.6	2,568.4	2,672.4	2,677.7	2,764.8	2,778.2	2,794.4
8/26/2018	2,376.5	2,330.9	2,357.1	2,351.2	2,359.7	2,375.8	2,470.8	2,564.1	2,704.0	2,790.4	2,964.8	3,136.9
8/27/2018	2,920.5	2,845.2	2,825.0	2,865.6	2,995.1	3,262.1	3,351.6	3,487.7	3,620.8	3,827.3	3,949.3	4,095.4
8/28/2018	3,059.4	2,941.5	2,877.0	2,889.6	3,045.1	3,302.1	3,352.4	3,411.3	3,497.6	3,610.7	3,662.8	3,843.6
8/29/2018	2,917.8	2,821.4	2,765.2	2,815.5	2,958.0	3,203.3	3,365.2	3,447.4	3,453.2	3,510.0	3,609.3	3,789.5
8/30/2018	2,635.4	2,553.3	2,557.1	2,562.2	2,673.6	2,823.7	2,961.2	2,970.3	2,950.5	3,031.5	3,090.9	3,155.0
8/31/2018	2,478.9	2,456.9	2,415.3	2,416.0	2,545.7	2,748.7	2,823.4	2,882.7	2,986.6	3,116.4	3,193.6	3,331.1
9/1/2018	2,537.7	2,464.9	2,420.8	2,353.5	2,375.0	2,390.7	2,431.1	2,519.8	2,749.5	2,887.8	3,031.4	3,133.6
9/2/2018	2,532.6	2,431.8	2,343.6	2,369.3	2,340.2	2,378.1	2,392.9	2,511.0	2,735.5	2,904.2	3,129.9	3,208.6
9/3/2018	2,654.0	2,571.0	2,433.9	2,426.8	2,432.6	2,427.0	2,418.5	2,529.7	2,773.1	3,121.3	3,338.1	3,519.3
9/4/2018	2,664.8	2,592.8	2,588.0	2,626.8	2,801.8	2,992.5	3,142.7	3,283.6	3,323.9	3,603.3	3,856.2	4,014.5
9/5/2018	2,976.7	2,876.6	2,727.3	2,758.9	2,927.0	3,095.2	3,160.4	3,253.2	3,383.1	3,576.4	3,747.1	3,931.4
9/6/2018	2,935.0	2,847.9	2,802.1	2,852.5	3,007.2	3,191.1	3,307.8	3,340.6	3,408.2	3,456.3	3,502.0	3,545.1
9/7/2018	2,640.1	2,538.1	2,530.8	2,591.2	2,735.9	2,959.2	3,047.1	3,003.7	3,057.0	3,152.0	3,173.9	3,206.7
9/8/2018	2,354.6	2,327.2	2,267.6	2,367.3	2,391.1	2,456.8	2,483.5	2,587.7	2,635.3	2,641.2	2,690.9	2,719.8
9/9/2018	2,206.2	2,172.3	2,161.7	2,145.3	2,179.3	2,113.0	2,255.5	2,137.0	2,205.8	2,297.9	2,417.2	2,433.3

Indiana Michigan Power Company - Hourly Internal Load (MW)
Note: Hours refelct EST

DATE	HR1	HR2	HR3	HR4	HR5	HR6	HR7	HR8	HR9	HR10	HR11	HR12
9/10/2018	2,193.9	2,178.8	2,201.8	2,240.8	2,375.7	2,627.1	2,720.5	2,747.7	2,787.4	2,827.7	2,881.5	2,880.3
9/11/2018	2,285.5	2,290.8	2,275.8	2,291.9	2,422.3	2,641.8	2,775.6	2,831.2	2,880.6	2,959.6	2,998.8	3,043.0
9/12/2018	2,347.6	2,327.3	2,304.9	2,316.3	2,458.4	2,661.0	2,800.5	2,817.5	2,884.2	2,994.2	3,013.2	2,982.6
9/13/2018	2,422.1	2,343.6	2,396.3	2,423.8	2,542.6	2,797.3	2,920.4	2,939.1	2,975.7	2,934.9	3,089.3	3,119.0
9/14/2018	2,396.3	2,376.7	2,357.9	2,387.9	2,507.2	2,699.1	2,832.3	2,924.2	2,928.2	3,077.5	3,045.4	3,268.5
9/15/2018	2,391.4	2,307.4	2,236.4	2,308.6	2,353.3	2,422.5	2,417.6	2,448.7	2,635.5	2,760.3	2,830.2	2,948.1
9/16/2018	2,438.8	2,289.8	2,271.1	2,233.8	2,288.1	2,322.7	2,344.0	2,454.1	2,575.5	2,734.9	2,852.2	3,017.1
9/17/2018	2,621.3	2,569.3	2,535.8	2,571.4	2,738.3	2,961.5	3,111.7	3,078.9	3,094.0	3,305.1	3,512.1	3,727.5
9/18/2018	2,666.4	2,620.9	2,582.8	2,558.0	2,651.6	2,849.3	2,919.4	2,961.7	3,083.7	3,246.6	3,385.7	3,531.9
9/19/2018	2,700.7	2,552.6	2,536.8	2,625.3	2,807.0	3,019.6	3,093.4	3,141.0	3,152.5	3,278.1	3,342.1	3,446.4
9/20/2018	2,606.1	2,627.1	2,515.1	2,565.5	2,690.0	2,937.1	3,079.1	3,111.2	3,267.5	3,430.1	3,519.7	3,817.5
9/21/2018	2,892.7	2,758.6	2,792.6	2,781.2	2,907.2	3,136.6	3,292.3	3,279.6	3,470.4	3,507.3	3,479.3	3,551.8
9/22/2018	2,310.0	2,233.7	2,170.6	2,148.4	2,172.7	2,274.2	2,310.6	2,355.2	2,440.3	2,497.0	2,518.4	2,466.5
9/23/2018	2,041.1	1,953.0	1,927.4	1,973.3	1,979.1	1,958.2	2,063.6	2,151.1	2,212.2	2,314.2	2,318.0	2,369.9
9/24/2018	2,183.5	2,143.4	2,228.2	2,296.6	2,440.5	2,599.3	2,769.5	2,819.5	2,870.5	2,956.7	2,954.5	3,001.7
9/25/2018	2,362.8	2,303.5	2,307.4	2,412.2	2,570.5	2,861.7	2,997.6	3,017.8	2,974.4	3,171.4	3,153.0	3,229.6
9/26/2018	2,462.8	2,419.4	2,412.0	2,460.2	2,616.7	2,830.4	2,951.8	2,949.3	2,949.6	2,964.9	3,018.0	3,037.1
9/27/2018	2,267.3	2,242.6	2,224.2	2,282.6	2,413.6	2,641.6	2,753.0	2,780.2	2,785.0	2,780.8	2,845.2	2,840.1
9/28/2018	2,234.8	2,239.0	2,222.8	2,279.7	2,449.4	2,632.2	2,778.3	2,776.9	2,773.0	2,790.5	2,836.4	2,787.1
9/29/2018	2,141.4	2,077.2	2,063.9	2,110.5	2,153.1	2,215.5	2,287.3	2,332.9	2,405.9	2,380.5	2,389.4	2,392.9
9/30/2018	2,041.3	1,999.2	1,951.0	1,951.8	1,964.9	2,035.1	2,097.7	2,165.9	2,259.1	2,274.3	2,370.5	2,441.8
10/1/2018	2,296.8	2,189.4	2,232.5	2,297.8	2,458.2	2,665.0	2,800.7	2,804.3	2,833.2	2,876.4	2,879.4	2,942.9
10/2/2018	2,564.2	2,484.7	2,421.8	2,499.8	2,626.2	2,840.1	3,023.2	3,061.5	3,115.1	3,116.2	3,136.0	3,161.7
10/3/2018	2,408.8	2,370.0	2,347.2	2,392.3	2,519.1	2,717.2	2,766.0	2,768.2	2,777.9	2,857.6	2,955.4	3,046.8
10/4/2018	2,656.7	2,658.9	2,547.8	2,642.4	2,783.6	3,062.3	3,189.4	3,132.9	3,160.8	3,155.5	3,152.5	3,202.6
10/5/2018	2,214.8	2,222.6	2,195.9	2,357.7	2,451.6	2,651.7	2,844.7	2,901.0	2,889.1	2,894.3	2,903.0	2,848.3
10/6/2018	2,223.4	2,181.0	2,209.2	2,217.5	2,288.9	2,353.0	2,461.8	2,557.3	2,578.8	2,670.0	2,748.7	2,749.0
10/7/2018	2,167.4	2,180.4	2,160.2	2,147.6	2,154.6	2,179.8	2,254.8	2,304.9	2,365.0	2,460.7	2,488.6	2,525.1

Indiana Michigan Power Company - Hourly Internal Load (MW)
Note: Hours refelct EST

DATE	HR1	HR2	HR3	HR4	HR5	HR6	HR7	HR8	HR9	HR10	HR11	HR12
10/8/2018	2,319.6	2,236.5	2,314.1	2,368.1	2,527.0	2,683.0	2,883.4	2,872.1	2,946.2	3,096.4	3,197.7	3,351.2
10/9/2018	2,600.5	2,504.2	2,472.6	2,567.9	2,714.2	2,921.9	2,980.3	3,045.4	3,148.6	3,301.5	3,356.4	3,532.0
10/10/2018	2,650.9	2,594.8	2,553.0	2,577.3	2,698.0	2,925.1	3,123.4	3,142.3	3,173.2	3,218.5	3,240.7	3,255.6
10/11/2018	2,468.4	2,374.3	2,368.2	2,382.7	2,566.9	2,720.6	2,837.2	2,857.6	2,772.0	2,773.6	2,910.6	2,889.3
10/12/2018	2,214.2	2,224.6	2,221.0	2,288.7	2,415.5	2,593.8	2,731.5	2,729.1	2,741.9	2,812.2	2,723.5	2,771.9
10/13/2018	2,230.5	2,184.3	2,162.8	2,218.7	2,263.2	2,298.8	2,415.9	2,395.7	2,492.8	2,533.6	2,455.0	2,463.6
10/14/2018	2,150.0	2,152.7	2,085.3	2,165.2	2,178.3	2,201.7	2,286.1	2,287.7	2,327.5	2,317.0	2,353.3	2,350.3
10/15/2018	2,191.8	2,175.2	2,213.5	2,251.6	2,466.2	2,733.9	2,876.2	2,859.0	2,834.5	2,861.1	2,827.1	2,879.6
10/16/2018	2,450.7	2,416.1	2,430.9	2,437.4	2,510.8	2,812.4	2,925.4	2,960.6	2,925.9	2,852.2	2,845.9	2,860.1
10/17/2018	2,455.5	2,423.0	2,406.9	2,419.7	2,563.8	2,772.3	2,938.2	2,863.8	2,929.7	2,920.9	2,883.4	2,913.2
10/18/2018	2,446.7	2,426.5	2,453.7	2,521.6	2,656.0	2,810.2	2,957.0	3,043.2	3,001.2	3,001.7	2,974.6	2,909.6
10/19/2018	2,382.2	2,391.4	2,392.6	2,401.3	2,554.6	2,746.1	2,904.1	2,946.9	2,854.7	2,915.7	2,890.9	2,883.1
10/20/2018	2,305.3	2,233.6	2,200.6	2,204.7	2,276.7	2,371.8	2,436.2	2,483.5	2,548.3	2,550.9	2,475.6	2,435.0
10/21/2018	2,167.2	2,124.9	2,112.7	2,099.9	2,156.6	2,201.7	2,266.1	2,321.9	2,363.4	2,416.3	2,418.9	2,398.2
10/22/2018	2,295.4	2,292.4	2,331.1	2,396.3	2,485.5	2,630.1	2,753.5	2,716.7	2,716.4	2,690.0	2,680.1	2,672.9
10/23/2018	2,149.8	2,130.2	2,117.8	2,189.5	2,315.5	2,522.5	2,650.0	2,640.7	2,617.2	2,613.8	2,590.9	2,587.1
10/24/2018	2,085.8	2,075.6	2,090.3	2,166.7	2,324.7	2,551.5	2,706.1	2,710.9	2,696.2	2,673.6	2,649.7	2,659.8
10/25/2018	2,200.4	2,173.2	2,191.3	2,248.0	2,404.1	2,623.5	2,782.5	2,775.2	2,767.5	2,771.5	2,751.8	2,691.8
10/26/2018	2,207.9	2,228.5	2,240.2	2,285.3	2,411.8	2,637.0	2,784.7	2,765.9	2,770.6	2,834.8	2,833.0	2,843.1
10/27/2018	2,198.6	2,190.8	2,215.0	2,226.3	2,295.3	2,301.8	2,407.5	2,448.2	2,496.2	2,503.4	2,516.7	2,511.5
10/28/2018	2,125.9	2,084.7	2,066.7	2,089.3	2,085.3	2,129.0	2,234.3	2,387.0	2,393.7	2,353.5	2,504.7	2,511.8
10/29/2018	2,190.1	2,192.7	2,215.3	2,289.3	2,455.8	2,662.4	2,838.9	2,760.2	2,764.1	2,733.0	2,728.4	2,762.1
10/30/2018	2,373.7	2,311.2	2,310.5	2,414.9	2,562.9	2,734.7	2,917.9	2,902.4	2,902.7	2,877.7	2,914.7	2,863.5
10/31/2018	2,282.9	2,280.5	2,283.9	2,334.6	2,488.5	2,701.5	2,830.1	2,840.9	2,832.1	2,878.2	2,874.9	2,802.9
11/1/2018	2,339.0	2,305.9	2,275.8	2,370.8	2,548.8	2,734.3	2,914.6	2,961.6	2,956.7	3,017.9	2,991.1	2,972.8
11/2/2018	2,387.8	2,328.7	2,306.6	2,317.4	2,486.1	2,658.1	2,773.6	2,845.1	2,838.2	2,821.1	2,752.0	2,706.4
11/3/2018	2,262.0	2,212.3	2,212.8	2,208.4	2,259.8	2,356.6	2,456.7	2,482.6	2,527.7	2,512.8	2,498.4	2,444.6
11/4/2018	2,202.5	2,169.0	2,170.9	2,154.3	2,172.7	2,185.8	2,246.1	2,293.5	2,412.3	2,417.2	2,439.3	2,372.3

Indiana Michigan Power Company - Hourly Internal Load (MW)
Note: Hours refelct EST

DATE	HR1	HR2	HR3	HR4	HR5	HR6	HR7	HR8	HR9	HR10	HR11	HR12
11/5/2018	2,265.8	2,223.9	2,198.5	2,202.2	2,268.6	2,446.3	2,699.3	2,809.6	2,826.3	2,835.3	2,837.3	2,816.6
11/6/2018	2,455.5	2,379.5	2,370.3	2,343.1	2,370.6	2,540.6	2,767.9	2,873.7	2,907.6	2,910.7	2,935.0	2,948.9
11/7/2018	2,442.2	2,391.5	2,376.2	2,415.3	2,464.9	2,649.4	2,883.5	2,978.7	2,985.6	2,980.9	3,004.1	2,984.5
11/8/2018	2,481.4	2,446.6	2,327.4	2,412.0	2,434.8	2,564.8	2,784.8	2,910.7	2,895.9	2,949.4	2,954.3	2,938.4
11/9/2018	2,457.2	2,422.1	2,481.4	2,493.7	2,514.4	2,712.7	2,920.5	3,008.6	2,919.1	2,995.6	3,043.2	3,047.6
11/10/2018	2,424.5	2,407.0	2,385.2	2,421.4	2,436.4	2,569.8	2,652.9	2,772.4	2,840.0	2,874.2	2,870.8	2,821.1
11/11/2018	2,479.2	2,436.2	2,387.0	2,385.6	2,430.8	2,462.9	2,517.9	2,572.1	2,615.6	2,624.4	2,607.0	2,607.3
11/12/2018	2,519.7	2,459.3	2,462.3	2,492.2	2,592.6	2,743.6	2,860.6	3,023.3	3,045.5	3,036.9	3,051.1	3,025.1
11/13/2018	2,636.8	2,554.6	2,544.2	2,542.9	2,629.2	2,754.1	2,912.8	2,962.4	2,957.3	2,920.5	2,893.4	2,850.0
11/14/2018	2,700.1	2,689.6	2,661.9	2,699.4	2,748.0	2,896.0	3,097.7	3,193.7	3,174.4	3,131.8	3,082.0	3,087.3
11/15/2018	2,867.9	2,853.0	2,827.7	2,853.7	2,929.4	3,073.6	3,233.9	3,347.8	3,348.6	3,359.7	3,352.2	3,323.2
11/16/2018	2,761.2	2,674.5	2,644.5	2,691.3	2,758.0	2,867.5	3,033.6	3,195.4	3,220.6	3,234.0	3,257.9	3,155.2
11/17/2018	2,535.7	2,494.3	2,421.8	2,449.8	2,443.3	2,523.1	2,592.3	2,687.8	2,761.6	2,799.3	2,781.8	2,796.3
11/18/2018	2,454.2	2,408.5	2,343.7	2,377.7	2,392.8	2,421.3	2,475.9	2,556.1	2,623.9	2,674.5	2,645.8	2,626.6
11/19/2018	2,559.2	2,521.4	2,531.1	2,551.0	2,622.9	2,827.9	3,023.5	3,172.5	3,095.5	3,092.5	3,110.5	3,115.1
11/20/2018	2,636.2	2,572.2	2,580.3	2,588.1	2,652.1	2,707.3	2,993.1	3,054.5	3,124.8	3,129.8	3,167.9	3,127.2
11/21/2018	2,742.3	2,709.4	2,681.8	2,650.6	2,705.7	2,827.7	3,008.9	3,122.8	3,155.4	3,097.0	3,018.5	3,070.2
11/22/2018	2,489.5	2,418.7	2,390.0	2,360.4	2,388.2	2,415.9	2,439.4	2,534.4	2,627.4	2,699.4	2,710.9	2,740.8
11/23/2018	2,381.9	2,372.1	2,333.1	2,320.5	2,261.3	2,364.1	2,457.7	2,542.8	2,574.6	2,562.7	2,538.3	2,498.0
11/24/2018	2,348.4	2,313.1	2,273.3	2,268.8	2,252.2	2,268.8	2,323.5	2,397.7	2,441.4	2,515.2	2,570.4	2,570.4
11/25/2018	2,233.2	2,139.8	2,142.6	2,104.4	2,119.9	2,162.6	2,268.0	2,331.7	2,370.1	2,419.1	2,445.5	2,455.3
11/26/2018	2,484.3	2,410.1	2,328.8	2,410.1	2,569.5	2,693.7	2,923.4	3,051.6	3,098.5	3,102.9	3,156.5	3,155.9
11/27/2018	2,706.2	2,628.7	2,584.1	2,644.2	2,700.6	2,849.9	3,096.2	3,229.7	3,197.9	3,263.3	3,253.2	3,257.9
11/28/2018	2,809.6	2,769.6	2,704.2	2,712.7	2,773.6	2,926.3	3,056.5	3,173.0	3,158.9	3,149.4	3,143.1	3,130.8
11/29/2018	2,818.0	2,777.5	2,714.1	2,602.2	2,680.8	2,833.4	3,083.5	3,232.4	3,240.5	3,225.3	3,247.3	3,220.0
11/30/2018	2,660.6	2,611.2	2,578.3	2,560.6	2,637.1	2,741.0	2,966.7	3,044.7	3,102.3	3,079.0	3,062.8	3,069.2
12/1/2018	2,562.5	2,482.4	2,457.6	2,455.1	2,495.1	2,575.0	2,658.2	2,782.3	2,842.8	2,916.4	2,902.3	2,911.2
12/2/2018	2,363.3	2,241.6	2,217.2	2,205.8	2,212.2	2,249.1	2,303.2	2,389.4	2,443.3	2,479.1	2,460.5	2,476.7

Indiana Michigan Power Company - Hourly Internal Load (MW)
Note: Hours refelct EST

DATE	HR1	HR2	HR3	HR4	HR5	HR6	HR7	HR8	HR9	HR10	HR11	HR12
12/3/2018	2,422.8	2,435.6	2,407.8	2,425.5	2,514.4	2,640.8	2,891.4	3,079.9	3,075.2	3,084.7	3,070.1	3,122.4
12/4/2018	2,615.8	2,564.2	2,506.5	2,463.1	2,666.5	2,816.9	3,033.2	3,154.9	3,195.0	3,168.9	3,219.2	3,174.7
12/5/2018	2,807.7	2,811.7	2,790.0	2,759.9	2,808.8	2,953.7	3,162.9	3,290.0	3,281.7	3,275.3	3,309.2	3,250.6
12/6/2018	2,794.4	2,743.0	2,762.1	2,752.6	2,811.9	2,956.6	3,166.0	3,314.6	3,300.8	3,244.4	3,260.5	3,247.7
12/7/2018	2,717.3	2,720.2	2,707.4	2,771.1	2,810.3	3,018.1	3,220.1	3,348.0	3,305.3	3,260.5	3,227.5	3,220.3
12/8/2018	2,669.3	2,606.7	2,601.2	2,584.6	2,630.4	2,646.8	2,726.7	2,840.1	2,905.2	2,941.7	2,961.9	2,940.2
12/9/2018	2,653.0	2,628.3	2,598.6	2,599.1	2,617.5	2,648.3	2,735.8	2,803.2	2,869.6	2,885.1	2,769.7	2,753.2
12/10/2018	2,701.8	2,707.3	2,709.4	2,689.5	2,744.4	2,919.0	3,175.2	3,371.6	3,376.2	3,381.9	3,406.5	3,359.9
12/11/2018	2,960.5	2,921.4	2,907.4	2,905.5	2,944.8	3,099.5	3,344.1	3,378.8	3,334.8	3,343.9	3,243.7	3,233.9
12/12/2018	2,784.4	2,756.0	2,733.3	2,728.8	2,812.8	2,936.9	3,169.8	3,274.8	3,253.0	3,238.7	3,195.2	3,077.6
12/13/2018	2,638.0	2,608.6	2,605.9	2,612.5	2,677.0	2,890.5	3,143.1	3,257.1	3,265.4	3,220.7	3,203.8	3,126.3
12/14/2018	2,614.8	2,475.6	2,425.3	2,509.4	2,493.6	2,688.3	2,946.6	2,992.9	3,021.3	3,048.4	3,080.4	3,040.2
12/15/2018	2,492.1	2,463.3	2,445.5	2,468.9	2,497.4	2,562.0	2,649.3	2,744.4	2,817.1	2,904.6	2,890.1	2,839.1
12/16/2018	2,409.8	2,376.3	2,350.1	2,367.6	2,354.5	2,366.1	2,414.3	2,528.5	2,574.8	2,602.0	2,600.5	2,560.6
12/17/2018	2,486.6	2,454.5	2,490.1	2,507.2	2,585.3	2,783.5	3,036.7	3,148.4	3,137.3	3,118.6	3,103.4	3,065.5
12/18/2018	2,696.0	2,658.7	2,658.2	2,676.5	2,738.1	2,885.6	3,101.6	3,259.6	3,249.5	3,214.8	3,141.3	3,104.3
12/19/2018	2,734.0	2,683.0	2,627.8	2,630.5	2,671.0	2,813.2	3,034.2	3,077.3	3,065.2	3,024.6	2,980.6	2,928.9
12/20/2018	2,508.8	2,532.0	2,399.8	2,488.0	2,532.8	2,681.7	2,959.8	3,101.0	3,130.0	3,064.1	3,058.8	3,032.3
12/21/2018	2,570.7	2,550.2	2,526.2	2,518.8	2,590.9	2,724.5	2,898.3	2,996.9	3,011.2	2,978.4	3,058.2	3,011.0
12/22/2018	2,478.6	2,438.4	2,408.7	2,381.3	2,393.8	2,432.6	2,497.6	2,590.7	2,678.9	2,730.7	2,739.8	2,736.2
12/23/2018	2,415.6	2,334.2	2,338.6	2,274.7	2,225.6	2,284.7	2,345.6	2,407.8	2,552.2	2,598.6	2,597.4	2,602.0
12/24/2018	2,316.6	2,240.7	2,219.7	2,175.4	2,204.9	2,297.4	2,411.3	2,458.7	2,492.6	2,523.6	2,448.5	2,427.8
12/25/2018	2,180.3	2,120.5	2,079.6	2,067.6	2,065.9	2,090.8	2,152.0	2,229.1	2,271.4	2,302.1	2,305.2	2,274.5
12/26/2018	2,060.5	2,028.5	2,026.2	2,048.1	2,111.0	2,254.9	2,448.1	2,628.6	2,827.4	2,831.1	2,792.5	2,762.5
12/27/2018	2,428.5	2,412.2	2,398.9	2,351.1	2,394.1	2,564.6	2,667.5	2,766.2	2,848.6	2,886.1	2,943.2	2,976.0
12/28/2018	2,281.1	2,260.0	2,242.0	2,205.7	2,240.1	2,337.0	2,525.3	2,603.5	2,660.9	2,708.0	2,700.9	2,656.5
12/29/2018	2,439.9	2,381.5	2,329.2	2,320.9	2,351.2	2,365.3	2,381.6	2,499.6	2,561.4	2,533.9	2,655.3	2,661.8
12/30/2018	2,392.5	2,325.2	2,285.7	2,257.7	2,285.0	2,306.1	2,335.1	2,455.7	2,502.4	2,573.9	2,512.2	2,494.5

Indiana Michigan Power Company - Hourly Internal Load (MW)
Note: Hours refelct EST

DATE	HR1	HR2	HR3	HR4	HR5	HR6	HR7	HR8	HR9	HR10	HR11	HR12
12/31/2018	2,368.0	2,301.0	2,256.5	2,287.5	2,340.2	2,418.3	2,529.5	2,594.1	2,660.7	2,749.9	2,771.8	2,784.0

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Note: Hours I

DATE	HR13	HR14	HR15	HR16	HR17	HR18	HR19	HR20	HR21	HR22	HR23	HR24
1/1/2018	3,052.9	3,022.4	2,986.3	2,996.3	3,048.5	3,203.5	3,350.7	3,353.6	3,310.5	3,267.1	3,210.5	3,157.6
1/2/2018	3,553.0	3,503.6	3,425.6	3,383.6	3,389.9	3,507.8	3,653.7	3,696.3	3,663.3	3,539.0	3,475.2	3,381.5
1/3/2018	3,590.9	3,529.8	3,466.5	3,439.5	3,464.4	3,541.7	3,579.1	3,500.2	3,482.5	3,415.8	3,302.5	3,219.1
1/4/2018	3,484.5	3,441.8	3,408.8	3,399.1	3,389.0	3,502.5	3,580.9	3,565.1	3,507.6	3,427.4	3,338.0	3,225.3
1/5/2018	3,510.7	3,478.2	3,455.6	3,415.8	3,410.2	3,487.1	3,548.3	3,533.3	3,499.3	3,431.4	3,318.0	3,219.3
1/6/2018	3,166.2	3,117.9	3,079.7	3,064.2	3,071.3	3,189.1	3,314.7	3,261.1	3,248.3	3,213.4	3,171.3	3,060.3
1/7/2018	3,094.8	3,061.9	2,987.3	2,983.3	3,008.0	3,083.8	3,159.6	3,130.3	3,103.6	3,031.8	2,930.5	2,898.6
1/8/2018	3,299.2	3,293.4	3,249.9	3,166.5	3,182.2	3,218.3	3,296.8	3,271.0	3,276.6	3,176.3	3,025.7	2,916.3
1/9/2018	3,267.7	3,195.2	3,126.0	3,101.8	3,081.8	3,114.8	3,269.6	3,266.4	3,204.5	3,164.5	3,035.9	2,885.6
1/10/2018	3,169.8	3,171.5	3,102.8	3,063.7	3,047.0	3,100.8	3,113.6	3,041.9	2,989.9	2,904.9	2,717.9	2,678.9
1/11/2018	2,859.2	2,844.3	2,803.9	2,783.3	2,807.6	2,815.0	2,903.9	2,883.0	2,875.9	2,782.0	2,715.7	2,641.6
1/12/2018	3,332.6	3,360.7	3,351.8	3,315.8	3,307.1	3,305.5	3,368.9	3,393.5	3,362.0	3,276.7	3,159.5	3,042.6
1/13/2018	3,075.6	3,052.8	3,046.1	3,023.2	3,051.3	3,119.6	3,192.6	3,174.7	3,126.0	3,031.3	2,987.8	2,915.0
1/14/2018	3,027.8	2,991.7	2,952.0	2,953.4	2,986.4	3,097.8	3,236.9	3,214.1	3,227.6	3,212.7	3,101.1	3,055.9
1/15/2018	3,513.0	3,482.3	3,437.7	3,382.4	3,378.3	3,430.1	3,482.6	3,463.9	3,425.5	3,373.2	3,262.0	3,165.7
1/16/2018	3,667.6	3,594.3	3,508.5	3,491.6	3,491.0	3,537.2	3,636.2	3,621.7	3,614.5	3,516.1	3,402.0	3,270.0
1/17/2018	3,420.3	3,456.5	3,383.4	3,324.1	3,338.0	3,420.5	3,531.6	3,547.3	3,496.8	3,426.6	3,321.3	3,268.2
1/18/2018	3,476.3	3,435.1	3,363.9	3,301.6	3,294.6	3,359.1	3,496.6	3,474.0	3,440.6	3,339.0	3,207.4	3,125.3
1/19/2018	3,265.8	3,198.9	3,129.3	3,080.0	3,060.0	3,129.7	3,201.1	3,193.1	3,156.2	3,066.6	2,938.0	2,828.2
1/20/2018	2,714.9	2,663.2	2,588.4	2,516.4	2,575.2	2,696.0	2,803.4	2,784.9	2,715.5	2,637.3	2,570.9	2,466.3
1/21/2018	2,645.0	2,614.3	2,619.0	2,634.1	2,668.6	2,661.3	2,800.0	2,813.5	2,730.4	2,724.3	2,600.4	2,553.4
1/22/2018	3,079.8	3,050.7	3,020.3	2,956.2	2,935.9	2,951.7	2,995.5	2,982.3	2,920.3	2,852.2	2,634.3	2,589.6
1/23/2018	3,199.8	3,205.9	3,177.2	3,153.1	3,150.9	3,198.1	3,242.1	3,180.5	3,130.1	3,089.8	2,942.1	2,786.5
1/24/2018	3,048.8	3,039.6	2,992.0	2,959.5	2,961.2	2,976.2	3,133.6	3,121.8	3,126.6	3,062.1	2,949.8	2,861.3
1/25/2018	3,266.0	3,214.3	3,109.7	3,062.3	3,003.7	3,070.3	3,202.5	3,214.7	3,157.6	3,086.5	2,955.6	2,814.4
1/26/2018	2,993.6	3,040.7	2,942.7	2,877.2	2,843.3	2,848.0	2,935.6	2,938.8	2,884.3	2,807.0	2,682.9	2,569.9
1/27/2018	2,764.1	2,730.4	2,641.2	2,577.5	2,559.2	2,577.5	2,700.3	2,702.5	2,676.4	2,635.8	2,505.3	2,458.7
1/28/2018	2,527.4	2,484.4	2,457.0	2,464.5	2,498.0	2,584.4	2,747.3	2,792.5	2,800.1	2,744.2	2,660.0	2,596.6

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Note: Hours

DATE	HR13	HR14	HR15	HR16	HR17	HR18	HR19	HR20	HR21	HR22	HR23	HR24
1/29/2018	3,287.2	3,306.7	3,266.3	3,222.1	3,201.4	3,244.1	3,315.4	3,321.3	3,274.9	3,171.3	3,047.7	2,868.7
1/30/2018	3,282.7	3,238.0	3,227.8	3,172.6	3,140.7	3,195.8	3,263.8	3,276.2	3,251.2	3,192.5	3,086.4	3,014.1
1/31/2018	3,231.1	3,245.3	3,197.6	3,064.4	3,056.0	3,091.8	3,182.1	3,169.8	3,152.7	3,031.7	2,916.5	2,826.8
2/1/2018	3,246.0	3,276.3	3,289.4	3,308.4	3,294.0	3,283.9	3,404.2	3,388.9	3,357.0	3,285.3	3,176.2	2,996.1
2/2/2018	3,409.4	3,388.0	3,299.1	3,229.2	3,177.3	3,182.4	3,202.1	3,259.4	3,263.9	3,229.8	3,084.4	3,019.5
2/3/2018	3,018.8	3,014.4	2,951.6	2,947.1	2,951.4	2,988.0	3,040.6	3,016.0	2,978.7	2,878.0	2,732.6	2,700.0
2/4/2018	2,837.4	2,830.1	2,849.1	2,877.3	2,920.6	3,002.6	3,074.5	3,068.1	3,065.0	3,038.3	2,946.0	2,886.4
2/5/2018	3,369.5	3,288.4	3,268.0	3,279.1	3,271.6	3,294.1	3,450.0	3,461.5	3,402.2	3,308.9	3,193.0	3,108.9
2/6/2018	3,096.0	3,063.1	3,025.7	2,989.1	2,985.9	3,056.8	3,200.9	3,243.9	3,175.6	3,086.6	3,020.5	2,950.8
2/7/2018	3,361.9	3,355.8	3,331.2	3,241.7	3,271.0	3,293.3	3,350.7	3,380.4	3,355.1	3,272.7	3,171.2	3,050.5
2/8/2018	3,393.1	3,357.7	3,280.1	3,233.7	3,222.2	3,228.7	3,350.8	3,351.9	3,323.8	3,258.1	3,151.2	3,058.7
2/9/2018	3,242.7	3,205.1	3,117.5	3,047.1	3,007.5	3,029.2	3,112.6	3,080.0	3,055.5	2,979.2	2,853.3	2,779.2
2/10/2018	2,983.1	2,954.6	2,916.4	2,920.6	2,897.9	2,950.1	3,004.2	3,012.1	2,989.2	2,897.5	2,801.0	2,749.3
2/11/2018	2,819.3	2,805.5	2,786.1	2,807.0	2,841.7	2,882.6	2,999.0	3,024.5	3,040.0	2,983.6	2,884.8	2,827.9
2/12/2018	3,267.2	3,173.9	3,100.8	3,019.6	3,005.5	3,028.9	3,171.1	3,269.8	3,235.4	3,175.3	3,033.4	2,948.7
2/13/2018	3,205.6	3,142.3	3,044.8	3,012.0	3,015.6	3,041.6	3,151.4	3,210.8	3,158.6	3,049.9	2,953.9	2,809.9
2/14/2018	3,109.1	3,114.7	3,041.0	3,017.9	3,014.9	3,036.5	3,076.0	3,089.4	3,055.0	2,972.2	2,838.4	2,671.8
2/15/2018	3,063.0	3,036.8	2,945.2	2,898.6	2,881.0	2,894.5	2,955.7	2,963.8	2,877.1	2,798.9	2,672.8	2,570.1
2/16/2018	3,072.7	3,046.0	2,975.8	2,930.5	2,912.0	2,895.4	2,958.0	2,996.8	2,976.8	2,927.0	2,849.1	2,698.6
2/17/2018	2,974.5	2,892.6	2,807.7	2,772.2	2,768.8	2,871.7	2,969.5	2,965.6	2,873.5	2,752.7	2,648.6	2,519.9
2/18/2018	2,632.9	2,575.8	2,574.5	2,543.9	2,520.4	2,594.9	2,705.3	2,806.2	2,798.1	2,678.7	2,646.1	2,584.1
2/19/2018	3,126.3	2,954.4	2,987.9	2,912.2	2,886.9	2,913.5	2,950.7	2,947.6	2,879.5	2,772.6	2,648.9	2,555.1
2/20/2018	2,922.3	2,893.3	2,845.9	2,720.2	2,771.0	2,773.0	2,810.5	2,845.1	2,783.1	2,698.1	2,583.5	2,514.9
2/21/2018	2,894.5	2,883.2	2,864.3	2,804.2	2,781.0	2,818.4	2,944.7	2,956.3	2,999.4	2,939.7	2,854.5	2,742.0
2/22/2018	2,984.8	2,948.4	2,939.4	2,914.8	2,926.9	2,893.3	3,005.6	3,055.0	2,987.4	2,939.8	2,843.2	2,727.8
2/23/2018	2,713.3	2,678.9	2,625.6	2,584.8	2,559.7	2,532.5	2,593.5	2,591.2	2,543.4	2,483.6	2,384.2	2,274.0
2/24/2018	2,579.6	2,580.2	2,550.9	2,532.2	2,497.5	2,553.6	2,643.5	2,684.6	2,655.8	2,607.9	2,508.4	2,416.5
2/25/2018	2,578.6	2,531.5	2,512.4	2,474.9	2,508.3	2,556.9	2,669.4	2,774.2	2,762.1	2,700.8	2,588.7	2,452.7

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Note: Hours

DATE	HR13	HR14	HR15	HR16	HR17	HR18	HR19	HR20	HR21	HR22	HR23	HR24
2/26/2018	2,923.9	2,864.6	2,876.2	2,792.8	2,772.1	2,721.1	2,829.2	2,948.9	2,940.1	2,860.8	2,753.3	2,628.5
2/27/2018	2,965.2	2,838.4	2,803.8	2,766.2	2,712.2	2,691.5	2,787.4	2,854.1	2,811.1	2,771.1	2,647.2	2,537.5
2/28/2018	2,929.7	2,873.6	2,841.2	2,771.1	2,674.8	2,724.7	2,838.1	2,886.6	2,846.1	2,795.9	2,686.9	2,547.6
3/1/2018	3,135.2	3,113.9	3,061.2	3,003.4	3,015.0	2,975.4	3,006.3	3,085.0	2,973.9	2,972.8	2,837.7	2,726.0
3/2/2018	3,006.4	2,936.3	2,863.9	2,798.2	2,748.0	2,713.5	2,792.9	2,868.8	2,902.0	2,816.4	2,722.8	2,621.4
3/3/2018	2,653.2	2,619.2	2,552.4	2,499.9	2,493.6	2,523.3	2,564.4	2,704.8	2,682.1	2,637.6	2,577.2	2,524.4
3/4/2018	2,567.4	2,527.7	2,492.6	2,488.2	2,510.4	2,522.7	2,641.1	2,761.3	2,793.2	2,774.1	2,669.7	2,620.0
3/5/2018	3,137.3	3,124.6	3,082.1	3,027.1	2,991.3	3,011.0	3,071.0	3,119.7	3,075.5	2,996.7	2,854.7	2,711.0
3/6/2018	2,824.1	2,803.9	2,778.9	2,748.9	2,753.8	2,799.3	2,875.2	2,905.0	2,921.7	2,882.6	2,798.4	2,671.6
3/7/2018	3,229.1	3,222.2	3,181.0	3,137.6	3,091.1	3,075.9	3,114.5	3,215.3	3,109.3	3,071.7	2,945.1	2,870.4
3/8/2018	3,250.5	3,269.0	3,197.5	3,144.7	3,169.1	3,144.6	3,183.4	3,255.6	3,219.8	3,092.8	2,991.6	2,868.3
3/9/2018	3,107.4	3,024.9	3,009.3	2,926.3	2,865.3	2,849.4	2,888.2	2,972.7	2,961.1	2,898.6	2,850.7	2,712.1
3/10/2018	2,676.1	2,653.8	2,585.9	2,564.8	2,511.3	2,534.4	2,569.0	2,703.4	2,729.2	2,710.0	2,564.3	2,489.7
3/11/2018	2,571.0	2,534.3	2,505.1	2,498.4	2,523.8	2,608.4	2,725.6	2,868.4	2,829.9	2,739.8	2,668.1	2,596.6
3/12/2018	3,191.2	3,109.6	2,938.3	2,908.0	2,965.0	2,946.0	2,984.2	3,087.6	3,057.1	2,916.7	2,814.9	2,733.5
3/13/2018	3,145.2	3,088.8	3,037.1	2,952.1	2,970.8	3,032.3	3,055.9	3,165.7	3,117.4	2,993.3	2,886.2	2,804.7
3/14/2018	3,089.0	3,057.5	3,019.2	2,965.3	2,941.3	2,948.9	2,968.3	3,087.4	3,021.4	2,901.7	2,802.7	2,686.6
3/15/2018	3,022.9	2,965.4	2,911.1	2,868.2	2,807.4	2,810.7	2,847.0	3,006.0	3,003.8	2,888.2	2,768.9	2,710.1
3/16/2018	3,033.3	2,947.4	2,873.2	2,852.1	2,783.6	2,787.5	2,836.3	2,898.1	2,886.3	2,760.7	2,632.1	2,584.5
3/17/2018	2,708.2	2,637.9	2,570.7	2,595.5	2,564.3	2,553.8	2,589.7	2,688.1	2,664.5	2,586.2	2,526.5	2,471.1
3/18/2018	2,470.2	2,398.4	2,384.3	2,372.9	2,383.3	2,407.3	2,497.5	2,646.6	2,640.6	2,532.9	2,486.5	2,464.5
3/19/2018	2,996.2	2,954.2	2,875.6	2,874.5	2,811.5	2,878.6	2,878.2	3,014.3	2,988.8	2,881.6	2,716.3	2,690.5
3/20/2018	3,100.8	3,040.8	2,967.9	2,967.0	2,967.2	2,986.4	3,017.3	3,126.6	3,019.2	2,871.9	2,789.9	2,745.0
3/21/2018	2,908.6	2,837.0	2,779.8	2,745.4	2,717.5	2,841.0	2,882.5	2,912.0	2,842.0	2,724.9	2,721.7	2,685.6
3/22/2018	3,058.0	2,913.5	2,912.3	2,836.1	2,804.7	2,769.3	2,827.0	2,903.3	2,881.7	2,823.2	2,692.6	2,614.0
3/23/2018	2,966.9	2,871.0	2,798.0	2,729.5	2,673.2	2,640.0	2,674.9	2,802.6	2,817.0	2,670.1	2,608.2	2,542.3
3/24/2018	2,787.2	2,698.4	2,737.3	2,740.5	2,728.3	2,711.3	2,720.2	2,744.3	2,767.4	2,667.7	2,599.6	2,520.4
3/25/2018	2,641.2	2,551.7	2,551.7	2,562.7	2,578.5	2,552.4	2,637.4	2,778.6	2,789.8	2,716.3	2,656.7	2,594.8

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Note: Hours ı

DATE	HR13	HR14	HR15	HR16	HR17	HR18	HR19	HR20	HR21	HR22	HR23	HR24
3/26/2018	2,927.2	2,906.5	2,848.1	2,832.0	2,812.0	2,801.3	2,890.3	2,921.1	2,859.9	2,760.5	2,614.5	2,534.5
3/27/2018	3,037.0	2,981.0	2,908.5	2,881.6	2,901.9	2,881.7	2,894.1	2,915.9	2,836.6	2,699.9	2,602.5	2,490.9
3/28/2018	3,003.0	2,945.9	2,858.1	2,819.5	2,795.5	2,780.5	2,763.4	2,854.2	2,815.8	2,685.3	2,576.9	2,501.4
3/29/2018	3,054.9	3,007.2	2,942.0	2,900.4	2,906.1	2,823.1	2,816.0	2,855.6	2,829.0	2,675.2	2,513.8	2,465.3
3/30/2018	2,630.2	2,573.4	2,504.9	2,437.2	2,387.6	2,388.1	2,340.5	2,481.6	2,545.9	2,430.5	2,352.3	2,319.1
3/31/2018	2,561.7	2,514.2	2,501.1	2,485.8	2,445.7	2,453.7	2,426.1	2,561.4	2,525.4	2,424.1	2,331.0	2,239.7
4/1/2018	2,264.9	2,192.5	2,192.4	2,247.8	2,289.2	2,366.1	2,456.4	2,562.1	2,635.0	2,603.2	2,541.3	2,468.9
4/2/2018	2,897.0	2,827.6	2,768.9	2,742.9	2,697.0	2,701.2	2,740.6	2,819.5	2,786.5	2,698.0	2,556.1	2,498.6
4/3/2018	3,039.3	3,010.6	2,958.3	2,913.5	2,852.6	2,815.7	2,822.8	2,849.6	2,595.1	2,449.9	2,421.8	2,407.4
4/4/2018	3,152.8	3,057.6	2,955.8	2,957.7	2,892.6	2,895.9	2,929.8	2,983.3	2,946.5	2,832.0	2,744.0	2,698.1
4/5/2018	2,971.4	2,899.4	2,850.2	2,815.2	2,783.7	2,811.6	2,849.8	2,854.6	2,848.1	2,658.2	2,589.0	2,575.5
4/6/2018	2,965.7	2,939.5	2,893.6	2,858.2	2,878.2	2,859.0	2,884.9	2,938.4	2,908.6	2,791.8	2,675.2	2,602.8
4/7/2018	2,707.7	2,663.0	2,643.7	2,613.2	2,582.9	2,532.8	2,605.1	2,687.7	2,715.9	2,645.3	2,597.2	2,539.6
4/8/2018	2,582.0	2,503.8	2,456.4	2,467.6	2,508.1	2,515.4	2,528.8	2,664.2	2,737.7	2,664.1	2,589.1	2,507.2
4/9/2018	3,089.4	3,018.4	2,914.8	2,932.0	2,908.7	2,833.2	2,888.7	2,972.7	2,922.3	2,777.2	2,670.6	2,620.9
4/10/2018	2,990.2	2,916.0	2,884.0	2,831.5	2,805.0	2,797.7	2,800.1	2,865.8	2,846.6	2,757.3	2,624.8	2,561.9
4/11/2018	2,716.2	2,637.0	2,555.5	2,499.7	2,459.9	2,497.2	2,579.4	2,720.4	2,657.9	2,583.5	2,466.9	2,407.4
4/12/2018	2,844.2	2,817.6	2,713.2	2,712.7	2,607.2	2,599.7	2,580.6	2,687.4	2,666.9	2,562.6	2,443.6	2,315.1
4/13/2018	2,804.6	2,782.4	2,707.5	2,670.9	2,639.1	2,636.5	2,593.3	2,652.4	2,615.5	2,456.8	2,299.9	2,238.6
4/14/2018	2,597.5	2,574.3	2,565.0	2,574.7	2,584.7	2,560.8	2,516.4	2,619.2	2,629.1	2,541.8	2,488.8	2,474.2
4/15/2018	2,508.5	2,409.3	2,497.4	2,491.5	2,574.2	2,580.5	2,610.0	2,677.5	2,643.5	2,557.8	2,485.3	2,430.2
4/16/2018	3,234.2	3,187.3	3,150.0	3,107.7	3,079.4	3,068.7	3,065.6	3,108.8	3,022.9	2,880.0	2,783.9	2,690.2
4/17/2018	3,188.0	3,138.4	3,068.9	2,995.7	2,913.1	2,871.0	2,905.6	2,941.7	2,989.5	2,868.3	2,679.6	2,664.4
4/18/2018	2,993.2	2,882.5	2,875.3	2,904.3	2,842.2	2,855.9	2,860.9	2,900.9	2,875.5	2,740.3	2,663.5	2,606.4
4/19/2018	2,958.0	2,881.9	2,834.5	2,775.4	2,736.5	2,666.8	2,729.6	2,785.4	2,804.9	2,699.5	2,594.4	2,536.0
4/20/2018	2,812.4	2,716.4	2,661.8	2,609.6	2,549.5	2,493.4	2,502.6	2,558.6	2,664.0	2,585.2	2,456.6	2,337.2
4/21/2018	2,330.1	2,372.3	2,366.4	2,377.3	2,399.2	2,398.3	2,356.4	2,474.1	2,469.6	2,389.7	2,307.7	2,163.7
4/22/2018	2,341.2	2,292.0	2,302.1	2,237.5	2,287.5	2,309.3	2,304.3	2,484.5	2,530.4	2,414.0	2,323.1	2,240.7

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Note: Hours I

DATE	HR13	HR14	HR15	HR16	HR17	HR18	HR19	HR20	HR21	HR22	HR23	HR24
4/23/2018	2,839.0	2,791.1	2,767.4	2,772.8	2,740.3	2,725.1	2,716.0	2,742.3	2,703.7	2,604.2	2,458.5	2,344.0
4/24/2018	2,890.5	2,842.2	2,831.9	2,798.3	2,766.1	2,755.9	2,750.5	2,779.1	2,728.8	2,600.6	2,495.8	2,431.2
4/25/2018	2,822.8	2,819.9	2,789.7	2,761.6	2,655.9	2,622.0	2,651.5	2,664.5	2,714.2	2,545.4	2,451.6	2,367.5
4/26/2018	2,836.2	2,766.9	2,668.5	2,662.2	2,619.4	2,600.0	2,562.6	2,623.9	2,673.9	2,535.4	2,374.9	2,305.1
4/27/2018	2,778.3	2,729.6	2,668.7	2,646.1	2,634.0	2,610.3	2,534.3	2,641.0	2,543.7	2,506.0	2,345.1	2,294.2
4/28/2018	2,501.7	2,471.1	2,432.6	2,412.4	2,394.6	2,387.7	2,401.7	2,443.3	2,513.4	2,462.8	2,371.1	2,292.2
4/29/2018	2,321.0	2,268.7	2,270.3	2,281.5	2,269.6	2,305.8	2,375.1	2,446.0	2,487.8	2,457.2	2,374.4	2,288.6
4/30/2018	2,808.8	2,748.8	2,715.3	2,694.5	2,630.0	2,610.9	2,587.1	2,599.4	2,662.9	2,482.1	2,369.1	2,294.8
5/1/2018	2,726.9	2,712.9	2,685.6	2,685.0	2,655.6	2,658.9	2,639.6	2,711.2	2,714.8	2,584.5	2,409.8	2,325.2
5/2/2018	3,088.1	3,090.1	3,103.3	3,039.0	3,074.2	3,062.5	3,070.1	3,051.5	3,030.3	2,868.8	2,670.5	2,496.9
5/3/2018	3,067.1	3,056.6	3,026.4	3,005.3	2,952.8	2,896.4	2,864.1	2,879.7	2,887.4	2,744.3	2,607.8	2,484.8
5/4/2018	2,934.2	2,895.6	2,838.2	2,761.0	2,734.8	2,706.4	2,647.7	2,568.9	2,656.0	2,516.1	2,417.1	2,165.0
5/5/2018	2,463.4	2,500.3	2,527.9	2,555.4	2,546.1	2,521.5	2,461.2	2,475.2	2,508.6	2,356.2	2,255.2	2,192.6
5/6/2018	2,486.6	2,517.8	2,520.4	2,521.3	2,558.8	2,573.5	2,588.0	2,549.0	2,585.8	2,486.4	2,378.8	2,268.4
5/7/2018	2,916.8	2,919.6	2,858.4	2,831.3	2,840.7	2,837.8	2,752.5	2,759.6	2,782.6	2,621.3	2,470.3	2,315.6
5/8/2018	2,974.4	2,930.5	2,977.7	2,879.8	2,841.1	2,945.3	2,932.5	2,890.9	2,896.4	2,755.5	2,591.3	2,458.2
5/9/2018	3,054.5	3,051.7	3,073.0	3,033.0	2,989.0	3,000.9	2,951.7	2,971.6	2,968.5	2,805.6	2,677.9	2,550.7
5/10/2018	2,978.9	2,958.1	2,947.3	2,922.8	2,891.3	2,836.1	2,763.2	2,763.3	2,792.2	2,624.5	2,456.6	2,377.4
5/11/2018	2,792.4	2,781.5	2,736.4	2,649.1	2,633.8	2,596.9	2,537.1	2,522.1	2,564.8	2,476.4	2,326.3	2,225.0
5/12/2018	2,416.9	2,407.0	2,415.2	2,343.2	2,333.7	2,317.3	2,295.4	2,301.4	2,330.3	2,229.8	2,152.6	2,005.3
5/13/2018	2,286.7	2,328.9	2,365.7	2,375.4	2,386.0	2,451.9	2,505.5	2,583.5	2,620.0	2,516.8	2,356.2	2,273.1
5/14/2018	3,063.3	3,051.0	3,016.5	3,040.1	3,091.5	3,094.3	3,069.8	3,068.4	3,034.4	2,892.5	2,715.7	2,534.7
5/15/2018	3,122.0	3,142.9	3,084.5	3,003.0	2,987.5	2,926.4	2,869.5	2,868.8	2,846.2	2,718.0	2,519.5	2,391.9
5/16/2018	2,848.2	2,847.6	2,843.1	2,848.1	2,850.2	2,841.1	2,820.1	2,790.3	2,746.8	2,643.1	2,485.2	2,358.7
5/17/2018	3,128.1	3,131.6	3,114.7	3,153.9	3,092.4	2,996.1	2,989.7	2,938.3	2,952.9	2,777.8	2,621.3	2,383.8
5/18/2018	2,898.7	2,884.2	2,828.2	2,780.2	2,744.4	2,683.6	2,667.2	2,701.5	2,615.0	2,424.3	2,340.6	2,292.1
5/19/2018	2,600.5	2,541.2	2,592.6	2,590.5	2,563.2	2,558.5	2,530.8	2,501.4	2,538.7	2,435.8	2,209.5	2,145.1
5/20/2018	2,455.3	2,494.1	2,501.3	2,509.5	2,586.1	2,601.5	2,587.2	2,593.4	2,597.5	2,579.8	2,426.4	2,274.2

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DATE	HR13	HR14	HR15	HR16	HR17	HR18	HR19	HR20	HR21	HR22	HR23	HR24
5/21/2018	3,007.8	2,991.4	2,962.0	2,933.3	2,908.2	2,853.0	2,860.4	2,811.8	2,817.9	2,691.8	2,408.2	2,380.6
5/22/2018	3,121.2	3,149.7	3,086.7	3,054.6	3,030.3	2,973.6	2,924.8	2,790.1	2,857.8	2,703.8	2,546.4	2,425.5
5/23/2018	3,120.1	3,101.2	3,086.7	3,087.0	3,118.4	3,053.3	3,003.4	2,908.6	2,990.2	2,860.1	2,513.0	2,393.1
5/24/2018	3,177.9	3,219.3	3,232.1	3,256.0	3,237.2	3,144.1	3,175.1	3,125.6	3,074.6	2,876.5	2,664.8	2,525.8
5/25/2018	3,326.0	3,354.0	3,391.4	3,439.1	3,396.8	3,373.7	3,261.8	3,108.4	3,103.6	2,948.5	2,721.5	2,574.7
5/26/2018	2,934.1	3,014.6	3,058.8	3,125.5	3,172.9	3,149.5	3,109.3	3,033.6	2,936.3	2,811.7	2,593.5	2,442.4
5/27/2018	3,173.3	3,187.0	3,284.7	3,333.4	3,376.6	3,375.6	3,275.2	3,139.3	3,080.3	2,910.9	2,710.4	2,596.1
5/28/2018	3,347.9	3,444.6	3,456.3	3,483.5	3,582.3	3,547.2	3,484.5	3,427.6	3,358.1	3,212.6	2,987.0	2,786.3
5/29/2018	4,036.0	4,102.8	4,064.4	4,072.2	4,001.4	3,904.6	3,785.1	3,684.7	3,633.3	3,435.4	3,209.7	3,013.3
5/30/2018	3,954.3	3,938.0	3,909.7	3,729.4	3,565.0	3,463.8	3,431.4	3,331.6	3,284.4	3,133.3	2,992.7	2,825.2
5/31/2018	3,899.4	3,913.4	3,861.6	3,823.9	3,811.8	3,762.4	3,672.1	3,571.1	3,480.3	3,310.6	3,089.0	2,896.5
6/1/2018	3,705.5	3,721.0	3,682.4	3,592.8	3,515.2	3,369.7	3,303.6	3,204.1	3,115.9	2,955.4	2,723.8	2,592.7
6/2/2018	2,731.0	2,750.6	2,923.2	2,986.4	3,023.1	3,014.2	2,970.3	2,847.7	2,786.8	2,722.9	2,606.6	2,481.0
6/3/2018	2,766.1	2,775.5	2,785.4	2,862.8	2,857.3	2,891.8	2,880.5	2,816.1	2,752.0	2,645.6	2,429.1	2,341.4
6/4/2018	3,000.5	3,055.8	2,987.9	2,989.1	3,013.6	2,977.7	2,945.5	2,874.9	2,856.5	2,775.1	2,598.6	2,446.3
6/5/2018	3,029.7	3,047.6	3,007.7	2,965.3	2,914.6	2,899.1	2,851.4	2,767.3	2,713.7	2,634.7	2,485.3	2,394.1
6/6/2018	2,804.5	2,820.4	2,813.4	2,834.8	2,821.3	2,779.9	2,796.2	2,769.2	2,752.0	2,738.9	2,591.6	2,433.5
6/7/2018	3,435.1	3,520.6	3,551.9	3,598.8	3,641.3	3,583.6	3,477.1	3,340.8	3,274.8	3,090.5	2,900.0	2,702.0
6/8/2018	3,266.8	3,161.6	3,250.5	3,248.9	3,251.8	3,213.4	3,008.4	2,908.2	2,874.7	2,772.7	2,622.1	2,562.8
6/9/2018	3,000.1	2,936.3	2,924.8	2,928.9	2,956.5	2,914.1	2,809.8	2,829.9	2,824.0	2,700.9	2,510.1	2,373.9
6/10/2018	2,648.2	2,617.1	2,629.8	2,626.2	2,720.3	2,685.0	2,721.9	2,701.4	2,666.9	2,637.4	2,502.7	2,431.9
6/11/2018	3,061.8	3,027.2	3,025.4	2,982.6	2,929.5	2,928.0	2,920.9	2,917.4	2,934.4	2,762.5	2,612.5	2,579.8
6/12/2018	3,225.3	3,268.3	3,228.8	3,223.8	3,210.0	3,201.8	3,116.9	3,113.7	3,105.1	3,017.4	2,851.6	2,723.4
6/13/2018	3,408.6	3,404.1	3,373.9	3,334.1	3,282.9	3,188.8	3,091.9	2,973.1	2,859.6	2,728.3	2,495.8	2,377.0
6/14/2018	3,365.9	3,409.4	3,434.2	3,474.8	3,421.6	3,367.1	3,244.7	3,138.0	3,035.5	2,960.7	2,756.3	2,583.7
6/15/2018	3,526.2	3,526.1	3,511.5	3,538.4	3,502.3	3,512.0	3,483.2	3,343.4	3,264.2	3,119.0	2,851.0	2,670.5
6/16/2018	3,372.8	3,442.7	3,545.4	3,591.0	3,675.8	3,673.5	3,642.2	3,521.0	3,442.0	3,262.0	3,081.2	2,899.1
6/17/2018	3,648.8	3,675.5	3,775.3	3,785.7	3,800.4	3,778.6	3,706.9	3,666.4	3,635.1	3,540.0	3,373.2	3,107.1

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DATE	HR13	HR14	HR15	HR16	HR17	HR18	HR19	HR20	HR21	HR22	HR23	HR24
6/18/2018	4,341.0	4,323.1	4,368.9	4,307.0	4,281.9	4,245.1	4,104.8	3,960.3	3,816.0	3,544.8	3,328.0	3,110.7
6/19/2018	3,906.8	3,886.6	3,848.8	3,764.3	3,629.4	3,522.4	3,377.3	3,298.9	3,219.5	3,116.3	2,910.8	2,774.3
6/20/2018	3,342.2	3,377.7	3,429.8	3,396.5	3,390.2	3,331.7	3,274.1	3,215.9	3,141.3	3,023.6	2,850.1	2,729.4
6/21/2018	3,020.2	2,990.0	2,920.5	2,853.0	2,809.7	2,762.8	2,735.9	2,722.2	2,717.7	2,639.1	2,581.5	2,373.8
6/22/2018	3,101.6	3,023.9	3,014.9	2,926.7	2,840.1	2,890.7	2,838.9	2,821.1	2,798.8	2,713.9	2,519.6	2,461.8
6/23/2018	2,743.5	2,730.0	2,770.2	2,760.4	2,746.0	2,722.8	2,653.9	2,646.5	2,612.2	2,547.1	2,429.7	2,338.9
6/24/2018	2,915.3	2,968.1	3,008.7	3,065.6	3,080.1	3,072.5	3,041.8	3,008.8	2,913.9	2,850.1	2,608.3	2,465.9
6/25/2018	3,373.2	3,425.5	3,450.4	3,463.1	3,463.9	3,421.1	3,357.8	3,226.2	3,165.0	3,032.9	2,816.1	2,658.6
6/26/2018	3,242.4	3,179.7	3,156.1	3,147.8	3,163.7	3,139.0	3,135.0	3,089.1	3,069.2	2,974.0	2,824.0	2,683.8
6/27/2018	3,328.6	3,334.3	3,273.9	3,238.1	3,176.4	3,236.4	3,174.5	3,161.2	3,085.2	2,996.5	2,766.9	2,633.4
6/28/2018	3,594.6	3,650.9	3,629.3	3,834.4	3,762.1	3,778.4	3,643.8	3,592.2	3,449.8	3,282.6	3,047.3	2,844.8
6/29/2018	3,904.6	4,021.7	4,041.7	4,020.5	4,079.3	3,959.9	3,912.7	3,767.5	3,736.2	3,504.9	3,329.4	3,151.5
6/30/2018	3,795.6	3,820.8	3,873.5	3,869.3	3,866.5	3,827.7	3,743.7	3,648.7	3,517.1	3,432.1	3,170.7	3,028.8
7/1/2018	3,684.4	3,681.7	3,776.2	3,838.5	3,799.0	3,841.4	3,760.1	3,631.2	3,499.6	3,387.8	3,196.1	3,057.4
7/2/2018	3,844.0	3,914.8	3,915.4	3,907.6	3,901.6	3,856.2	3,775.1	3,610.7	3,525.7	3,334.6	3,072.8	2,913.4
7/3/2018	4,028.1	4,101.1	4,088.7	4,104.0	4,065.6	3,980.6	3,870.6	3,692.8	3,584.9	3,398.4	3,243.0	3,030.5
7/4/2018	3,644.7	3,683.5	3,759.3	3,743.6	3,688.9	3,628.7	3,551.1	3,468.4	3,358.1	3,278.2	3,128.3	2,966.8
7/5/2018	4,031.0	4,031.5	3,907.7	3,890.6	3,833.7	3,736.3	3,592.1	3,486.4	3,320.5	3,200.1	2,998.0	2,880.0
7/6/2018	3,265.4	3,299.1	3,315.7	3,333.7	3,313.9	3,236.7	3,115.0	3,008.3	2,848.6	2,793.7	2,578.3	2,432.9
7/7/2018	2,755.0	2,800.5	2,878.4	2,923.5	2,983.2	2,999.4	2,930.1	2,862.3	2,755.4	2,683.9	2,533.8	2,366.5
7/8/2018	2,878.3	2,985.6	3,147.6	3,253.2	3,320.4	3,365.0	3,301.7	3,167.8	3,184.4	3,059.8	2,847.1	2,673.9
7/9/2018	3,874.8	3,944.4	3,951.9	4,020.2	4,028.0	3,980.5	3,965.5	3,826.0	3,710.9	3,514.8	3,310.0	3,102.5
7/10/2018	4,220.9	4,168.0	4,092.9	4,058.6	4,003.4	3,916.8	3,827.5	3,663.8	3,458.2	3,322.3	3,078.7	2,912.1
7/11/2018	3,510.7	3,578.7	3,622.1	3,649.6	3,624.4	3,601.1	3,538.8	3,404.7	3,295.2	3,142.7	2,991.9	2,819.9
7/12/2018	3,696.6	3,735.3	3,826.0	3,841.6	3,820.1	3,758.1	3,643.0	3,587.5	3,479.3	3,310.8	3,050.4	2,864.6
7/13/2018	3,850.4	3,938.8	4,011.7	3,985.6	4,012.9	3,926.9	3,850.3	3,713.6	3,565.6	3,427.3	3,136.3	2,914.5
7/14/2018	3,362.3	3,433.8	3,403.2	3,375.4	3,357.6	3,334.4	3,328.0	3,290.8	3,223.5	3,099.6	2,936.0	2,746.3
7/15/2018	3,538.2	3,631.6	3,703.5	3,760.3	3,738.3	3,662.4	3,592.7	3,502.3	3,469.3	3,358.3	3,198.7	2,985.6

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DATE	HR13	HR14	HR15	HR16	HR17	HR18	HR19	HR20	HR21	HR22	HR23	HR24
7/16/2018	4,142.1	4,148.2	4,102.0	4,063.8	4,005.5	3,932.5	3,872.0	3,772.9	3,647.4	3,451.9	3,262.0	3,009.2
7/17/2018	3,786.7	3,810.4	3,792.6	3,736.7	3,638.0	3,620.4	3,503.7	3,324.3	3,232.2	3,070.5	2,781.9	2,658.1
7/18/2018	3,483.2	3,526.8	3,523.8	3,567.9	3,568.5	3,563.5	3,439.6	3,256.0	3,167.2	3,095.3	2,904.6	2,753.7
7/19/2018	3,637.4	3,666.7	3,727.5	3,756.0	3,759.4	3,712.2	3,622.8	3,500.5	3,427.9	3,194.0	3,007.3	2,809.0
7/20/2018	3,506.2	3,480.7	3,373.5	3,208.4	3,117.7	3,065.3	2,981.7	2,937.6	2,917.1	2,836.0	2,638.9	2,546.6
7/21/2018	2,827.2	2,858.0	2,888.5	2,817.1	2,874.8	2,850.8	2,757.6	2,763.7	2,757.2	2,651.3	2,476.1	2,405.1
7/22/2018	2,932.3	2,980.2	2,979.4	2,976.9	2,914.8	2,947.5	2,885.0	2,743.4	2,717.4	2,727.6	2,587.9	2,512.0
7/23/2018	3,360.4	3,294.6	3,322.7	3,245.0	3,255.1	3,121.7	3,137.5	3,087.5	3,078.3	2,926.4	2,775.5	2,677.7
7/24/2018	3,207.5	3,284.0	3,326.8	3,371.2	3,396.5	3,381.6	3,378.6	3,350.5	3,269.8	3,047.7	2,791.6	2,645.2
7/25/2018	3,717.8	3,845.4	3,827.1	3,813.9	3,737.9	3,663.1	3,610.3	3,463.5	3,322.0	3,175.7	2,944.5	2,778.5
7/26/2018	3,593.7	3,610.3	3,654.4	3,634.9	3,541.2	3,502.9	3,430.1	3,313.0	3,209.2	3,016.3	2,830.7	2,659.4
7/27/2018	3,319.4	3,273.7	3,257.1	3,236.0	3,228.7	3,133.2	3,065.2	2,920.0	2,885.4	2,722.5	2,575.2	2,398.5
7/28/2018	2,877.6	2,917.8	2,915.6	2,948.4	2,942.9	2,930.8	2,857.2	2,765.9	2,687.3	2,622.4	2,487.7	2,371.8
7/29/2018	2,743.6	2,772.9	2,777.8	2,821.4	2,835.9	2,795.0	2,733.6	2,756.3	2,798.0	2,734.5	2,584.0	2,509.9
7/30/2018	3,141.3	3,141.9	3,193.2	3,137.9	3,177.2	3,162.3	3,097.7	3,033.0	3,028.9	2,923.6	2,700.7	2,528.5
7/31/2018	3,198.5	3,173.7	3,045.9	3,010.4	3,105.8	3,074.0	3,071.6	3,063.5	2,989.1	2,895.6	2,710.4	2,563.8
8/1/2018	3,441.7	3,458.7	3,519.6	3,494.9	3,490.8	3,444.2	3,344.4	3,255.7	3,195.3	3,027.8	2,824.1	2,707.4
8/2/2018	3,639.8	3,704.7	3,736.4	3,760.0	3,693.7	3,529.2	3,389.3	3,288.2	3,254.8	3,072.1	2,919.9	2,701.9
8/3/2018	3,636.9	3,679.0	3,727.7	3,709.2	3,672.6	3,607.8	3,493.7	3,381.2	3,298.6	3,098.6	2,829.7	2,595.7
8/4/2018	3,535.8	3,550.9	3,671.0	3,773.0	3,780.3	3,717.0	3,655.8	3,524.5	3,442.0	3,269.6	3,085.2	2,879.9
8/5/2018	3,498.5	3,641.7	3,681.2	3,743.6	3,749.1	3,792.0	3,748.0	3,639.6	3,593.7	3,424.7	3,187.9	3,068.0
8/6/2018	4,024.0	4,046.8	3,985.6	3,911.5	3,849.6	3,854.9	3,824.5	3,696.9	3,553.3	3,284.3	3,067.1	2,844.0
8/7/2018	3,784.4	3,844.3	3,836.7	3,796.1	3,623.8	3,544.6	3,516.3	3,499.9	3,414.2	3,206.5	3,031.3	2,887.9
8/8/2018	3,493.7	3,518.8	3,465.4	3,425.4	3,400.0	3,392.8	3,391.6	3,305.7	3,248.9	3,089.9	2,918.6	2,734.3
8/9/2018	3,728.6	3,799.6	3,861.9	3,874.3	3,773.2	3,844.0	3,737.9	3,642.0	3,496.8	3,278.0	3,020.9	2,882.7
8/10/2018	3,597.4	3,668.6	3,742.5	3,710.5	3,726.9	3,598.5	3,479.4	3,330.6	3,320.8	3,102.6	2,899.5	2,792.6
8/11/2018	3,252.2	3,320.5	3,366.0	3,434.0	3,443.2	3,399.4	3,348.7	3,151.6	3,071.9	2,915.3	2,726.0	2,498.5
8/12/2018	3,178.9	3,192.7	3,371.5	3,445.3	3,479.9	3,467.2	3,425.6	3,351.9	3,264.9	3,098.8	2,913.2	2,738.6

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DATE	HR13	HR14	HR15	HR16	HR17	HR18	HR19	HR20	HR21	HR22	HR23	HR24
8/13/2018	3,788.3	3,907.5	3,900.2	3,862.5	3,775.2	3,739.2	3,739.5	3,565.0	3,495.8	3,283.9	3,019.7	2,816.9
8/14/2018	3,839.5	3,890.3	3,898.0	3,913.3	3,897.0	3,794.6	3,701.4	3,505.1	3,520.7	3,315.2	3,108.6	2,875.8
8/15/2018	3,748.7	3,750.6	3,708.4	3,642.2	3,548.2	3,521.3	3,389.8	3,329.1	3,333.6	3,135.9	2,896.3	2,774.1
8/16/2018	3,479.7	3,377.0	3,461.5	3,521.6	3,547.9	3,484.4	3,431.4	3,416.8	3,359.9	3,180.5	2,928.7	2,837.6
8/17/2018	3,600.4	3,560.4	3,540.0	3,498.7	3,444.5	3,364.4	3,209.5	3,147.4	3,074.4	2,954.3	2,820.6	2,677.1
8/18/2018	3,198.1	3,276.4	3,313.8	3,371.5	3,322.5	3,291.8	3,179.9	3,063.1	3,039.4	2,819.4	2,736.7	2,576.2
8/19/2018	3,130.3	3,197.6	3,288.9	3,360.8	3,404.1	3,396.5	3,330.8	3,274.3	3,159.8	2,983.6	2,811.7	2,655.8
8/20/2018	3,569.3	3,528.7	3,543.2	3,410.6	3,332.3	3,331.9	3,247.0	3,207.2	3,195.5	3,017.2	2,864.2	2,756.8
8/21/2018	3,300.5	3,311.7	3,306.6	3,326.1	3,272.9	3,219.2	3,154.7	3,115.2	3,113.2	2,882.7	2,731.5	2,589.1
8/22/2018	3,174.7	3,197.4	3,183.4	3,190.6	3,167.4	3,141.3	3,060.7	2,994.9	2,942.7	2,753.6	2,588.1	2,435.8
8/23/2018	3,101.7	3,220.2	3,266.4	3,289.5	3,277.1	3,227.3	3,174.2	3,116.1	3,059.2	2,853.3	2,680.1	2,523.8
8/24/2018	3,169.4	3,152.5	3,140.2	3,087.3	3,039.0	2,995.2	2,933.7	2,945.0	2,856.0	2,770.0	2,562.1	2,515.9
8/25/2018	2,832.0	2,813.2	2,841.0	2,877.7	2,850.2	2,889.5	2,823.4	2,862.9	2,849.6	2,758.7	2,583.4	2,459.9
8/26/2018	3,305.7	3,455.6	3,547.6	3,699.4	3,746.5	3,745.3	3,680.8	3,676.5	3,624.9	3,424.1	3,232.2	3,090.8
8/27/2018	4,191.3	4,232.3	4,248.2	4,232.7	4,215.4	4,155.4	4,031.8	3,930.9	3,789.3	3,566.0	3,380.6	3,208.9
8/28/2018	4,019.9	4,141.8	4,217.5	4,256.6	4,223.1	4,193.3	4,058.0	3,953.3	3,859.7	3,562.5	3,326.1	3,164.9
8/29/2018	3,852.2	3,841.8	3,798.9	3,605.8	3,623.1	3,401.4	3,376.5	3,404.5	3,314.5	3,102.5	2,898.6	2,740.9
8/30/2018	3,254.0	3,309.3	3,320.8	3,375.5	3,339.0	3,257.0	3,149.0	3,160.8	3,091.5	2,909.0	2,718.8	2,594.6
8/31/2018	3,466.2	3,498.7	3,607.0	3,634.9	3,580.2	3,475.8	3,369.5	3,298.5	3,205.7	3,009.3	2,812.2	2,670.6
9/1/2018	3,199.4	3,250.1	3,289.4	3,326.5	3,341.4	3,283.5	3,182.7	3,075.4	3,039.7	2,883.3	2,748.3	2,654.1
9/2/2018	3,349.6	3,440.0	3,479.4	3,532.3	3,542.9	3,509.7	3,430.5	3,342.9	3,273.3	3,111.6	2,882.3	2,776.7
9/3/2018	3,621.3	3,678.4	3,609.7	3,592.2	3,586.9	3,468.8	3,436.2	3,392.9	3,222.1	3,063.3	2,895.3	2,749.9
9/4/2018	4,184.1	4,228.7	4,168.1	4,255.4	4,286.1	4,197.7	4,066.6	3,950.0	3,828.0	3,556.1	3,314.9	3,136.0
9/5/2018	4,053.2	4,094.3	4,119.3	4,144.1	4,106.0	3,988.0	3,934.2	3,905.1	3,703.9	3,454.7	3,183.2	3,010.5
9/6/2018	3,580.0	3,637.2	3,568.3	3,548.4	3,421.5	3,318.4	3,284.7	3,318.8	3,238.2	3,049.4	2,898.7	2,735.5
9/7/2018	3,162.2	3,130.2	3,114.4	3,018.1	2,924.7	2,954.6	2,851.1	2,818.8	2,820.2	2,680.9	2,501.0	2,427.4
9/8/2018	2,710.0	2,721.9	2,659.0	2,675.8	2,642.3	2,610.8	2,605.5	2,672.8	2,628.9	2,530.0	2,364.6	2,296.6
9/9/2018	2,409.4	2,417.0	2,449.1	2,483.2	2,475.3	2,515.6	2,555.5	2,585.9	2,544.5	2,443.9	2,281.5	2,257.6

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DATE	HR13	HR14	HR15	HR16	HR17	HR18	HR19	HR20	HR21	HR22	HR23	HR24
9/10/2018	2,916.8	2,894.9	2,868.3	2,816.9	2,809.9	2,785.1	2,782.4	2,793.0	2,689.6	2,664.3	2,488.8	2,394.2
9/11/2018	3,066.2	2,978.0	3,025.8	3,062.1	3,065.5	3,001.3	2,997.2	2,983.4	2,928.1	2,699.2	2,468.4	2,431.0
9/12/2018	3,116.0	3,100.7	3,081.0	3,061.2	3,060.7	3,012.6	2,975.9	3,067.7	2,972.8	2,790.0	2,633.6	2,516.9
9/13/2018	3,244.8	3,335.2	3,323.6	3,311.7	3,328.9	3,247.3	3,135.6	3,196.4	3,074.3	2,893.7	2,674.4	2,529.9
9/14/2018	3,341.6	3,338.2	3,489.0	3,474.5	3,465.5	3,307.7	3,235.3	3,131.5	3,057.3	2,893.8	2,671.0	2,551.1
9/15/2018	3,053.6	3,046.4	3,216.7	3,343.1	3,333.8	3,302.8	3,153.9	3,144.6	3,070.4	2,870.0	2,735.4	2,581.9
9/16/2018	3,161.4	3,211.9	3,298.1	3,400.3	3,438.8	3,375.2	3,267.9	3,333.0	3,164.4	3,044.7	2,832.5	2,724.1
9/17/2018	3,868.2	3,884.4	3,936.8	3,990.0	3,926.1	3,865.4	3,732.5	3,683.8	3,466.3	3,204.4	2,944.8	2,751.1
9/18/2018	3,644.6	3,727.3	3,740.8	3,716.1	3,602.2	3,486.2	3,390.7	3,372.5	3,283.9	3,108.9	2,968.6	2,828.5
9/19/2018	3,583.4	3,641.6	3,727.5	3,765.4	3,692.1	3,612.1	3,532.7	3,491.7	3,353.6	3,119.6	2,962.7	2,757.8
9/20/2018	3,961.8	4,072.3	4,040.5	3,970.3	3,894.6	3,780.2	3,691.8	3,647.4	3,481.8	3,319.6	3,148.7	2,945.3
9/21/2018	3,559.3	3,560.3	3,519.5	3,448.1	3,376.7	3,210.1	3,090.4	3,004.4	2,933.6	2,754.8	2,549.4	2,425.6
9/22/2018	2,532.0	2,483.5	2,495.2	2,507.0	2,416.8	2,446.4	2,497.2	2,495.5	2,428.1	2,229.6	2,170.0	2,068.7
9/23/2018	2,388.0	2,403.7	2,467.1	2,513.3	2,528.3	2,549.3	2,582.1	2,618.0	2,489.2	2,365.5	2,319.1	2,228.3
9/24/2018	2,971.9	2,955.8	2,881.7	2,858.8	2,836.7	2,802.2	2,875.1	2,885.3	2,787.2	2,640.8	2,553.6	2,382.4
9/25/2018	3,253.2	3,164.6	3,231.9	3,202.2	3,173.1	3,161.5	3,167.9	3,162.1	2,994.6	2,812.8	2,676.0	2,617.5
9/26/2018	3,048.7	2,996.9	2,962.5	2,931.3	2,839.4	2,764.8	2,788.4	2,773.0	2,663.4	2,576.5	2,446.6	2,352.7
9/27/2018	2,898.5	2,877.9	2,793.5	2,741.0	2,694.9	2,629.2	2,677.9	2,758.0	2,689.8	2,546.0	2,410.8	2,293.3
9/28/2018	2,923.5	2,897.9	2,827.1	2,777.7	2,726.2	2,678.0	2,682.3	2,647.7	2,575.2	2,403.4	2,298.8	2,215.7
9/29/2018	2,400.7	2,360.8	2,405.4	2,418.5	360.2	2,422.7	2,462.7	2,443.2	2,414.9	2,306.5	2,197.9	2,105.6
9/30/2018	2,480.7	2,443.5	2,484.1	2,606.0	2,613.2	2,603.5	2,698.1	2,692.1	2,620.1	2,473.4	2,427.8	2,369.6
10/1/2018	3,109.5	3,135.8	3,156.2	3,118.5	3,166.1	3,136.3	3,144.2	3,162.0	3,049.0	2,906.9	2,776.9	2,673.9
10/2/2018	3,178.6	3,106.1	3,062.2	3,014.9	2,958.2	2,938.5	2,982.4	2,968.7	2,875.7	2,750.5	2,528.8	2,483.9
10/3/2018	3,134.9	3,200.0	3,218.9	3,240.4	3,272.8	3,344.7	3,336.8	3,358.1	3,236.4	3,038.6	2,896.3	2,856.9
10/4/2018	3,145.6	3,151.1	3,050.4	3,101.2	2,973.8	2,936.3	2,917.9	2,933.4	2,799.7	2,563.8	2,485.6	2,301.1
10/5/2018	2,854.5	2,819.1	2,810.5	2,729.4	2,707.1	2,633.1	2,676.2	2,701.4	2,628.3	2,465.8	2,401.8	2,333.0
10/6/2018	2,850.8	2,907.7	2,853.8	2,882.5	2,832.8	2,768.2	2,770.7	2,728.9	2,643.9	2,573.9	2,316.3	2,228.9
10/7/2018	2,576.1	2,645.5	2,679.9	2,735.0	2,746.2	2,728.1	2,823.4	2,774.6	2,654.5	2,555.3	2,458.4	2,356.0

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DATE	HR13	HR14	HR15	HR16	HR17	HR18	HR19	HR20	HR21	HR22	HR23	HR24
10/8/2018	3,430.0	3,538.1	3,599.5	3,553.9	3,493.6	3,329.2	3,346.2	3,244.6	3,119.7	2,910.7	2,749.0	2,660.6
10/9/2018	3,570.5	3,605.5	3,608.1	3,539.1	3,441.3	3,446.3	3,483.2	3,389.5	3,209.1	2,944.2	2,872.9	2,744.5
10/10/2018	3,207.2	3,199.8	3,181.5	3,116.9	3,052.8	3,042.2	3,125.7	3,066.4	2,988.3	2,866.4	2,696.9	2,581.8
10/11/2018	2,877.8	2,867.3	2,771.5	2,744.9	2,730.6	2,688.7	2,801.5	2,784.2	2,679.3	2,557.3	2,462.1	2,322.5
10/12/2018	2,738.3	2,724.5	2,646.6	2,665.5	2,649.5	2,666.7	2,675.1	2,734.9	2,656.1	2,543.8	2,374.4	2,278.1
10/13/2018	2,410.1	2,383.7	2,229.8	2,328.9	2,324.3	2,350.4	2,409.3	2,408.6	2,374.1	2,349.4	2,261.5	2,180.8
10/14/2018	2,348.9	2,332.3	2,327.2	2,262.5	2,326.5	2,374.5	2,533.1	2,558.5	2,475.9	2,341.7	2,296.2	2,180.9
10/15/2018	2,818.2	2,832.7	2,744.0	2,737.4	2,733.1	2,742.6	2,836.9	2,823.9	2,798.0	2,675.6	2,544.1	2,499.0
10/16/2018	2,857.9	2,851.8	2,787.1	2,731.0	2,690.9	2,724.3	2,783.9	2,741.7	2,727.1	2,588.8	2,544.2	2,479.5
10/17/2018	2,911.3	2,874.9	2,785.5	2,804.9	2,768.4	2,801.2	2,843.3	2,869.4	2,793.8	2,667.8	2,535.9	2,469.5
10/18/2018	2,882.4	2,799.2	2,737.0	2,739.4	2,672.5	2,601.8	2,791.8	2,818.0	2,728.3	2,594.4	2,521.1	2,456.8
10/19/2018	2,828.9	2,771.9	2,693.6	2,722.9	2,699.1	2,673.7	2,679.2	2,719.8	2,704.4	2,588.5	2,455.6	2,376.0
10/20/2018	2,396.4	2,331.3	2,344.9	2,299.1	2,374.4	2,417.4	2,426.2	2,469.4	2,409.8	2,337.5	2,259.5	2,212.7
10/21/2018	2,392.1	2,293.5	2,308.3	2,342.6	2,336.3	2,410.2	2,551.4	2,582.1	2,538.7	2,448.9	2,358.5	2,326.5
10/22/2018	2,644.3	2,587.9	2,540.3	2,506.9	2,475.4	2,488.3	2,562.3	2,538.6	2,490.5	2,372.8	2,276.3	2,192.4
10/23/2018	2,573.1	2,526.9	2,465.7	2,436.7	2,427.8	2,435.3	2,532.7	2,499.1	2,449.3	2,322.3	2,224.6	2,147.1
10/24/2018	2,611.2	2,555.0	2,484.1	2,450.6	2,443.2	2,475.8	2,558.7	2,554.8	2,509.9	2,401.0	2,303.8	2,240.5
10/25/2018	2,676.7	2,627.2	2,558.4	2,538.3	2,535.7	2,578.0	2,637.5	2,585.7	2,543.7	2,426.2	2,332.8	2,255.6
10/26/2018	2,758.9	2,701.1	2,626.5	2,620.3	2,590.3	2,607.7	2,626.7	2,578.0	2,504.6	2,397.9	2,288.9	2,215.1
10/27/2018	2,469.6	2,419.4	2,417.3	2,397.3	2,413.9	2,448.5	2,469.8	2,449.2	2,365.4	2,333.4	2,234.4	2,119.5
10/28/2018	2,467.5	2,405.7	2,460.2	2,501.3	2,525.3	2,544.3	2,582.0	2,547.2	2,494.9	2,407.6	2,285.9	2,188.5
10/29/2018	2,771.7	2,732.2	2,662.5	2,622.6	2,594.0	2,628.2	2,711.0	2,718.6	2,660.1	2,548.8	2,439.1	2,374.8
10/30/2018	2,885.0	2,790.0	2,708.6	2,645.5	2,649.7	2,722.7	2,796.9	2,739.8	2,657.4	2,538.1	2,465.8	2,361.2
10/31/2018	2,828.7	2,758.0	2,675.2	2,690.5	2,620.6	2,647.8	2,685.8	2,697.3	2,638.9	2,535.3	2,459.0	2,399.3
11/1/2018	2,884.6	2,842.8	2,862.0	2,858.9	2,857.0	2,900.7	2,917.3	2,852.8	2,761.1	2,685.8	2,578.0	2,478.7
11/2/2018	2,647.1	2,711.4	2,621.6	2,609.9	2,580.0	2,638.3	2,673.4	2,618.9	2,555.8	2,487.3	2,378.7	2,298.0
11/3/2018	2,379.4	2,330.7	2,318.2	2,301.9	2,325.0	2,411.3	2,465.2	2,470.4	2,443.0	2,429.9	2,366.3	2,300.2
11/4/2018	2,396.9	2,373.7	2,387.4	2,405.1	2,471.5	2,554.3	2,596.8	2,586.8	2,575.7	2,489.9	2,363.4	2,306.9

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DATE	HR13	HR14	HR15	HR16	HR17	HR18	HR19	HR20	HR21	HR22	HR23	HR24
11/5/2018	2,835.1	2,821.7	2,789.1	2,755.5	2,672.3	2,741.2	2,804.4	2,796.7	2,836.9	2,749.2	2,654.2	2,546.2
11/6/2018	2,918.1	2,933.6	2,896.8	2,833.1	2,807.6	2,861.1	2,875.3	2,865.1	2,811.7	2,699.3	2,561.6	2,489.2
11/7/2018	2,971.5	2,947.0	2,902.9	2,853.0	2,841.0	2,862.0	2,923.9	2,910.8	2,880.4	2,799.7	2,666.7	2,579.0
11/8/2018	2,917.7	2,895.0	2,843.7	2,795.6	2,782.8	2,793.0	2,906.2	2,902.0	2,859.6	2,800.9	2,685.2	2,553.0
11/9/2018	3,067.9	3,064.6	3,033.9	2,988.6	3,004.7	3,026.8	2,994.4	2,941.8	2,932.1	2,878.5	2,768.4	2,615.6
11/10/2018	2,831.0	2,767.6	2,746.8	2,704.5	2,699.8	2,774.0	2,807.4	2,761.7	2,738.2	2,648.5	2,552.7	2,556.8
11/11/2018	2,540.4	2,531.2	2,437.9	2,463.1	2,517.7	2,628.7	2,715.0	2,744.8	2,733.8	2,671.6	2,568.0	2,544.2
11/12/2018	3,047.8	3,056.1	3,011.4	2,993.2	3,009.7	3,050.5	3,075.0	3,064.6	3,037.8	2,933.0	2,822.3	2,708.2
11/13/2018	2,881.5	2,891.5	2,882.9	2,856.4	2,845.8	2,916.2	2,951.5	3,004.0	2,985.9	2,946.3	2,779.0	2,765.3
11/14/2018	3,088.7	3,054.6	3,016.8	2,990.6	3,027.2	3,096.7	3,132.8	3,127.2	3,087.5	3,074.8	2,969.0	2,904.0
11/15/2018	3,280.6	3,275.1	3,222.5	3,160.6	3,124.4	3,187.9	3,212.4	3,177.1	3,124.1	3,049.2	2,947.7	2,841.7
11/16/2018	3,133.0	3,121.9	3,076.5	3,025.7	2,995.9	3,039.2	2,993.0	2,976.9	2,922.4	2,860.7	2,724.5	2,616.3
11/17/2018	2,776.5	2,745.8	2,712.6	2,729.6	2,675.2	2,793.6	2,778.0	2,708.3	2,756.9	2,674.4	2,608.2	2,527.8
11/18/2018	2,590.8	2,604.1	2,626.1	2,570.8	2,667.9	2,729.3	2,803.8	2,805.2	2,767.7	2,727.7	2,613.5	2,530.4
11/19/2018	3,101.4	3,033.8	2,996.3	2,961.2	3,025.5	3,062.2	3,095.0	3,099.5	3,062.6	2,997.8	2,857.1	2,766.0
11/20/2018	3,076.5	3,108.3	3,056.1	3,024.8	3,011.1	3,065.1	3,083.5	3,098.6	3,032.4	2,928.4	2,873.1	2,804.2
11/21/2018	3,103.6	3,085.9	2,981.8	2,931.0	2,898.2	2,904.0	2,928.3	2,855.8	2,856.1	2,826.0	2,704.4	2,564.6
11/22/2018	2,638.8	2,539.0	2,500.4	2,461.1	2,480.7	2,501.9	2,602.5	2,609.6	2,553.1	2,557.2	2,501.7	2,430.6
11/23/2018	2,504.5	2,480.9	2,482.9	2,448.8	2,486.9	2,559.3	2,563.7	2,557.8	2,499.3	2,493.7	2,454.0	2,377.1
11/24/2018	2,518.9	2,504.6	2,471.5	2,451.0	2,453.4	2,554.0	2,528.8	2,507.5	2,448.2	2,407.4	2,345.3	2,280.6
11/25/2018	2,447.4	2,401.6	2,420.3	2,435.7	2,517.7	2,617.5	2,678.6	2,690.0	2,720.5	2,727.5	2,634.9	2,591.2
11/26/2018	3,152.3	3,148.6	3,113.7	3,094.5	3,115.0	3,176.9	3,181.7	3,203.7	3,072.9	3,034.1	2,870.1	2,774.2
11/27/2018	3,279.1	3,270.3	3,242.4	3,213.8	3,218.8	3,286.4	3,311.8	3,270.6	3,212.7	3,150.1	3,002.7	2,900.0
11/28/2018	3,097.6	3,088.9	3,035.8	2,992.3	3,008.5	3,088.7	3,113.9	3,214.6	3,172.9	3,100.4	2,974.2	2,895.6
11/29/2018	3,185.2	3,189.2	3,141.5	3,089.9	3,076.6	3,170.9	3,182.0	3,174.0	3,089.4	2,978.9	2,864.4	2,757.4
11/30/2018	2,997.1	2,973.4	2,948.6	2,894.1	2,883.1	2,973.7	2,976.0	2,956.3	2,890.3	2,851.1	2,770.4	2,654.1
12/1/2018	2,841.1	2,801.4	2,761.9	2,732.4	2,749.3	2,811.0	2,785.8	2,740.0	2,739.4	2,638.0	2,524.0	2,427.9
12/2/2018	2,514.0	2,534.8	2,522.2	2,518.6	2,581.9	2,769.9	2,811.3	2,820.1	2,792.8	2,709.7	2,634.4	2,535.3

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DATE	HR13	HR14	HR15	HR16	HR17	HR18	HR19	HR20	HR21	HR22	HR23	HR24
12/3/2018	3,107.7	3,087.3	3,047.4	3,001.9	3,033.2	3,119.9	3,134.9	3,115.3	3,083.0	2,996.4	2,839.2	2,737.2
12/4/2018	3,117.3	3,107.6	3,105.4	3,036.4	3,064.3	3,193.9	3,202.0	3,188.9	3,176.9	3,136.6	3,014.5	2,884.8
12/5/2018	3,293.3	3,321.4	3,275.8	3,244.0	3,245.1	3,316.4	3,328.6	3,277.4	3,237.5	3,155.4	3,061.5	2,911.3
12/6/2018	3,295.9	3,253.2	3,189.2	3,168.9	3,185.5	3,235.0	3,239.1	3,206.5	3,177.1	3,116.9	2,986.5	2,857.8
12/7/2018	3,149.3	3,137.3	3,056.9	2,991.6	3,030.3	3,116.9	3,101.0	3,072.4	3,009.6	2,962.1	2,851.8	2,762.3
12/8/2018	2,900.1	2,813.7	2,817.2	2,803.6	2,818.0	2,902.8	2,929.9	2,910.2	2,936.5	2,858.8	2,817.9	2,733.5
12/9/2018	2,764.5	2,717.2	2,671.3	2,674.3	2,718.6	2,884.8	2,962.9	2,971.6	2,975.1	2,884.2	2,849.7	2,770.7
12/10/2018	3,305.2	3,303.6	3,198.8	3,191.5	3,207.7	3,289.5	3,312.4	3,349.9	3,308.7	3,254.7	3,134.3	3,012.4
12/11/2018	3,208.2	3,161.9	3,119.6	3,052.7	3,086.0	3,233.0	3,221.8	3,233.9	3,229.1	3,164.8	3,014.9	2,899.0
12/12/2018	3,156.5	3,159.4	3,086.8	3,035.2	3,030.4	3,128.5	3,159.4	3,137.2	3,100.4	3,013.8	2,866.9	2,662.3
12/13/2018	3,136.0	3,069.9	3,030.9	2,979.0	2,985.4	3,091.0	3,127.3	3,108.7	3,070.6	2,963.5	2,845.9	2,721.9
12/14/2018	3,002.9	2,962.1	2,944.1	2,887.3	2,888.6	2,966.3	2,948.0	2,914.4	2,859.5	2,803.1	2,697.4	2,582.1
12/15/2018	2,802.8	2,733.8	2,666.5	2,668.8	2,731.3	2,787.3	2,818.7	2,811.1	2,787.4	2,710.8	2,618.4	2,528.5
12/16/2018	2,497.2	2,477.7	2,424.6	2,444.5	2,502.8	2,657.1	2,704.7	2,750.3	2,751.7	2,736.0	2,628.9	2,550.6
12/17/2018	3,041.4	3,019.1	2,932.9	2,919.8	2,916.3	3,067.1	3,100.4	3,083.8	3,095.5	3,027.6	2,879.3	2,758.8
12/18/2018	3,099.2	3,077.2	2,966.2	2,964.0	2,978.8	3,045.2	3,133.1	3,162.4	3,131.1	3,044.3	2,916.8	2,798.9
12/19/2018	2,875.4	2,830.2	2,775.6	2,727.3	2,739.9	2,869.2	2,972.2	3,011.6	2,989.1	2,923.9	2,846.2	2,665.3
12/20/2018	3,022.1	3,024.1	2,980.5	2,990.8	2,990.7	3,055.0	3,070.8	3,001.7	3,029.6	2,969.6	2,816.0	2,638.8
12/21/2018	2,988.1	2,986.3	2,950.5	2,934.9	2,908.8	3,003.0	2,965.2	2,883.1	2,905.0	2,846.6	2,730.1	2,594.3
12/22/2018	2,744.5	2,699.8	2,698.5	2,688.9	2,684.6	2,768.9	2,764.0	2,766.6	2,683.7	2,677.8	2,585.5	2,494.3
12/23/2018	2,595.6	2,551.8	2,548.1	2,511.5	2,551.5	2,626.1	2,698.9	2,690.0	2,656.8	2,615.9	2,493.6	2,393.4
12/24/2018	2,371.9	2,306.8	2,264.9	2,234.1	2,239.5	2,369.8	2,416.2	2,394.6	2,381.9	2,370.9	2,330.5	2,239.0
12/25/2018	2,226.7	2,129.0	2,065.1	2,044.8	2,046.9	2,164.3	2,250.5	2,261.0	2,264.1	2,247.2	2,193.2	2,112.7
12/26/2018	2,614.7	2,577.1	2,559.2	2,622.7	2,615.1	2,753.9	2,807.4	2,832.5	2,811.2	2,740.9	2,636.6	2,499.8
12/27/2018	2,988.3	2,990.3	2,913.2	2,844.8	2,832.1	2,903.9	2,885.3	2,814.8	2,757.0	2,689.6	2,535.1	2,450.1
12/28/2018	2,696.7	2,705.5	2,715.1	2,707.4	2,727.2	2,821.9	2,818.8	2,816.9	2,777.0	2,734.7	2,624.5	2,503.8
12/29/2018	2,620.9	2,615.6	2,601.1	2,579.5	2,614.9	2,700.8	2,705.9	2,720.6	2,694.5	2,631.4	2,532.8	2,491.4
12/30/2018	2,473.4	2,430.7	2,473.9	2,416.8	2,468.9	2,628.8	2,673.4	2,695.9	2,666.6	2,584.3	2,532.3	2,378.6

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DATE	HR13	HR14	HR15	HR16	HR17	HR18	HR19	HR20	HR21	HR22	HR23	HR24
12/31/2018	2,818.8	2,779.9	2,715.5	2,714.3	2,639.5	2,652.2	2,607.3	2,555.1	2,493.1	2,291.4	2,328.5	2,294.4

Exhibit F Stakeholder Process Exhibits

Communication and documentation of the Company's stakeholder interaction can be found on the Company's IRP website at the following address:

https://www.indianamichiganpower.com/info/projects/IntegratedResourcePlan/

The following is a list of the significant documents on the site:

1. IRP Stakeholder Education
2. IRP Questions and Comments
3. Workshop 1
4. Workshop 2
5. Workshop 3
6. Workshop 4

Exhibit G Cross Reference Table

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170 IAC 4-7-1 Definitions

see draft rule for definitions	**IRP Section**
170 IAC 4-7-2.6 Public advisory process	
Sec. 2.6.(b) The utility shall provide information requested by an interested party relating to the development of the utility's IRP. within 15 business days of a written request or as otherwise agreed to by the utility and the interested party. If a utility is unable to provide the requested information within 15 business days or the agreed timeframe, it shall provide a statement to the director and the requestor as to the reason it is unable to provide the requested information.	
Sec. 2.6 (c) The utility shall solicit, consider, and timely respond to all relevant input relating to the development of the utility's IRP provided by:	Section 1.3.1
(1) interested parties;	
(2) the OUCC;	
(3) the commission staff.	
Sec. 2.6 (d) The utility retains full responsibility for the content of its IRP.	
Sec. 2.6 (e) The utility shall conduct a public advisory process as follows:	
(1) Prior to submitting its IRP to the commission, the utility shall hold at least three meetings, a majority of which shall be held in the utility's service territory. The topics discussed in the meetings shall include, but not be limited to, the following:	
(A) An introduction to the IRP and public advisory process.	
(B) The utility's load forecast.	
(C) Evaluation of existing resources.	
(D) Evaluation of supply-side and demand-side resource alternatives, including:	
(i) associated costs;	
(ii) quantifiable benefits; and	
(iii) performance attributes.	
(E) Modeling methods.	
(F) Modeling inputs.	
(G) Treatment of risk and uncertainty.	
(H) Discussion seeking input on its candidate resource portfolios.	
(I) The utility's scenarios and sensitivities.	
(J) Discussion of the utility's preferred resource portfolio and the utility's rationale for its selection.	
(2) The utility may hold additional meetings.	
(3) The schedule for meetings shall:	
(A) be determined by the utility;	
(B) be consistent with its internal IRP development schedule; and	
(C) provide an opportunity for public participation in a timely manner so that it may affect the outcome of the IRP.	
(4) The utility or its designee shall:	
(A) chair the participation process;	
(B) schedule meetings;	
(C) develop and publish to its website agendas and relevant material for those meetings at least seven (7) calendar days prior to the meeting; and	
(D) develop and publish to its website meeting minutes within fifteen (15) calendar days following the meeting;	
(5) Interested parties may request that relevant items be placed on the agenda of the meetings if they provide adequate notice to the utility.	
(6) The utility shall take reasonable steps to notify:	
(A) its customers;	
(B) the commission;	
(C) interested parties; and	
(D) the OUCC.	
of its public advisory process.	
170 IAC 4-7-4 Integrated resource plan contents	
Sec. 4. An IRP must include the following:	
(1) At least a twenty (20) year future period for predicted or forecasted analyses.	Section 5.3
(2) An analysis of historical and forecasted levels of peak demand and energy usage in compliance with section 5(a) of this rule.	Section 2
(3) At least three (3) alternative forecasts of peak demand and energy usage in compliance with section 5(b) of this rule.	Section 5
(4) A description of the utility's existing resources in compliance with section 6(a) of this rule.	Section 3.2
(5) A description of the utility's process for selecting possible alternative future resources for meeting future demand for electric service, including a cost-benefit analysis, if performed.	Section 5
(6) A description of the possible alternative future resources for meeting future demand for electric service in compliance with section 6(b) of this rule.	Section 5.2.1

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(7) The resource screening analysis and resource summary table required by section 7 of this rule.	
(8) A description of the candidate resource portfolios and the process for developing candidate resource portfolios in compliance with section 8(a) and 8(b) of this rule.	Section 5.2.2
(9) A description of the utility's preferred resource portfolio and the information required by section 8(c) of this rule.	Section 5.3
(10) A short term action plan for the next three (3) year period to implement the utility's preferred resource portfolio and its workable strategy, pursuant to section 9 of this rule.	Section 6.1.1
(11) A discussion of the:	Section 5
(A) inputs;	
(B) methods; and	
(C) definitions;	
used by the utility in the IRP.	
(12) Appendices of the data sets and data sources used to establish alternative forecasts in section 5(b) of this rule. If the IRP references a third-party data source, the IRP must include for the relevant data:	Exhibits
(A) source title;	
(B) author;	
(C) publishing address;	
(D) date;	
(E) page number; and	
(F) an explanation of adjustments made to the data.	
The data must be submitted within two (2) weeks of submitting the IRP in an editable format, such as a comma separated value or excel spreadsheet file.	
(13) A description of the utility's effort to develop and maintain a database of electricity consumption patterns, disaggregated by:	section 4.4
(A) customer class;	
(B) rate class;	
(C) NAICS code;	
(D) DSM program; and	
(E) end-use.	
(14) The database in subdivision (13) may be developed using, but not limited to, the following methods:	
(A) Load research developed by the individual utility.	
(B) Load research developed in conjunction with another utility.	
(C) Load research developed by another utility and modified to meet the characteristics of that utility.	
(D) Engineering estimates.	
(E) Load data developed by a non-utility source.	
(15) A proposed schedule for industrial, commercial, and residential customer surveys to obtain data on:	
(A) end-use penetration;	
(B) end-use saturation rates; and	
(C) end-use electricity consumption patterns.	
(16) A discussion detailing how information from advanced metering infrastructure and smart grid, where available, will be used to enhance usage data and improve load forecasts, DSM programs, and other aspects of planning.	
(17) A discussion of the designated contemporary issues designated, if required by section 2.7(e).	
(18) A discussion of distributed generation within the service territory and theits potential effects on:	section 3.4.4
(A) generation, planning;	section 2
(B) transmission planning;	
(C) distribution planning; and	
(D) load forecasting.	
(19) For models used in the IRP, including optimization and dispatch models, a description of the model's structure and applicability.	Section 5.2.2
(20) A discussion of how the utility's fuel inventory and procurement planning practices have been taken into account and influenced the IRP development.	Section 3.2.2
(21) A discussion of how the utility's emission allowance inventory and procurement practices for an air emission have been considered and influenced the IRP development.	Section 3.3
(22) A description of the generation expansion planning criteria. The description must fully explain the basis for the criteria selected.	Section 5.2.1
(23) A discussion of how compliance costs for existing or reasonably anticipated air, land, or water environmental regulations impacting generation assets have been taken into account and influenced the IRP development.	Section 3.3
(24) A discussion of how the utilities' resource planning objectives, such as:	Section 5.3.2
(A) cost effectiveness;	
(B) rate impacts;	
(C) risks; and	
(D) uncertainty;	

were balanced in selecting its preferred resource portfolio.	
(25) A description and analysis of the utility's base case scenario, sometimes referred to a business as usual case or reference case. The base case scenario is the most likely future scenario and must meet the following criteria:	section 5.2.2
(A) Be an extension of the status quo, using the best estimate of forecasted electrical requirements, fuel price projections, and an objective analysis of the resources required over the planning horizon to reliably and economically satisfy electrical needs.	
(B) Include:	
(i) existing federal environmental laws;	
(ii) existing state laws, such as renewable energy requirements and energy efficiency laws; and	
(iii) existing policies, such as tax incentives for renewable resources.	
(C) Existing laws or policies continuing throughout at least some portion of the planning horizon with a high probability of expiration or repeal must be eliminated or altered when applicable.	
(D) Not include future resources, laws, or policies unless:	
(i) a utility subject to section 2.6 of this rule solicits stakeholder input regarding the inclusion and describes the input received;	
(ii) future resources have obtained the necessary regulatory approvals; and	
(iii) future laws and policies have a high probability of being enacted.	
A base case scenario need not align with the utility's preferred resource portfolio.	
(26) A description and analysis of alternative scenarios to the base case scenario, including comparison of the alternative scenarios to the base case scenario.	5.2.1-5
(27) A brief description of the models(s), focusing on the utility's Indiana jurisdictional facilities, of the following components of FERC Form 715:	section 3.5.8
(A) The most current power flow data models, studies, and sensitivity analysis.	
(B) Dynamic simulation on its transmission system, including interconnections, focused on the determination of the performance and stability of its transmission system on various fault conditions. The description must state whether the simulation meets the standards of the North American Electric Reliability Corporation (NERC).	
(C) Reliability criteria for transmission planning as well as the assessment practice used. This description must include the following:	
(i) The limits of the utility's transmission use.	
(ii) The utility's assessment practices developed through experience and study.	
(iii) Operating restrictions and limitations particular to the utility.	
(28) A list and description of the utility'smethods used by the utility in developing the IRP, including the following:	Section 5
(A) For models used in the IRP, the model's structure and reasoning for its use.	
(B) The utility's effort to develop and improve the methodology and inputs, including for its:	section 4.4
(i) load forecast;	
(ii) forecasted impact from demand-side programs;	
(iii) cost estimates; and	
(iv) analysis of risk and uncertainty.	
(29) An explanation, with supporting documentation, of the avoided cost calculation for each year in the forecast period, if the avoided cost calculation is used to screen demand-side resources. The avoided cost calculation must reflect timing factors specific to the resource under consideration such as project life and seasonal operation. The avoided cost calculation must include the following:	Section 4.4.4
(A) The avoided generating capacity cost adjusted for transmission and distribution losses and the reserve margin requirement.	
(B) The avoided transmission capacity cost.	
(C) The avoided distribution capacity cost.	
(D) The avoided operating cost, including:	
(i) fuel cost:	
(ii) plant operation and maintenance costs;	
(iii) spinning reserve;,	
(iv) emission allowances;,	
(v) environmental compliance costs, and	
(vi) transmission and distribution operation and maintenance costs.	
(30) A summary of the utility's most recent public advisory process, including:	Section 1.3.1
(A) Key issues discussed.	
(B) How the utility responded to the issues.	
(C) A description of how stakeholder input was used in developing the IRP.	
(31) A detailed explanation of the assessment of demand-side and supply-side resources considered to meet future customer electricity service needs.	Section 4.4
170 IAC 4-7-5 Energy and demand forecasts	
Sec. 5. (a) The analysis of historical and forecasted levels of peak demand and energy usage must include the following:	

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(1) Historical load shapes, including the following:	Section 2
(A) Annual load shapes.	
(B) Seasonal load shapes.	
(C) Monthly load shapes.	
(D) Selected weekly load shapes.	
(E) Selected daily load shapes, which shall include summer and winter peak days, and a typical weekday and weekend day.	
(2) Disaggregation of historical data and forecasts by:	
(A) customer class;	
(B) interruptible load;	
(C) end-use;	
where information permits.	
(3) Actual and weather normalized energy and demand levels.	
(4) A discussion of methods and processes used to weather normalize.	
(5) A minimum twenty (20) year period for peak demand and energy usage forecasts.	
(6) An evaluation of the performance of peak demand and energy usage for the previous ten (10) years, including the following:	
(A) Total system.	
(B) Customer classes, rate classes, or both.	
(C) Firm wholesale power sales.	
(7) A discussion of how the impact of historical DSM programs is reflected in or otherwise treated in the load forecast	
(8) Justification for the selected forecasting methodology.	
(9) A discussion of the potential changes under consideration to improve the credibility of the forecasted demand by improving the data quality, tools, and analysis.	
(10) For purposes of subdivisions (1) and (2), a utility may use utility specific data or data such as described in subdivision 4(14) of this rule.	
Sec. 5 (b) To establish plausible risk boundaries, the utility shall provide In providing at least three (3) alternative forecasts of peak demand and energy usage including	Section 2
(1) high;	
(2) low; and	
(3) most probable	
peak demand and energy use forecasts.	
Sec. 5 (c) In determining the peak demand and energy usage forecast to establish plausible risk boundaries as well as a forecast that is deemed by the utility, with stakeholder input, to be most probable, the utility shall consider likely based on alternative assumptions such as	Section 2
(1) Rate of change in population.	
(2) Economic activity.	
(3) Fuel prices, including competition.	
(4) Price elasticity.	
(5) Penetration of new technology.	
(6) Demographic changes in population.	
(7) Customer usage.	
(8) Changes in technology.	
(9) Behavioral factors affecting customer consumption.	
(10) State and federal energy policies.	
(11) State and federal environmental policies.	
170 IAC 4-7-6 Description of Available Resources	
Sec. 6. (a) In describing its existing electric power resources, the utility must include in its IRP the following information relevant to the 20 year planning period being evaluated:	
(1) The net and gross dependable generating capacity of the system and each generating unit.	Section 3.2
(2) The expected changes to existing generating capacity, including the following:	
(A) Retirements.	
(B) Deratings.	
(C) Plant life extensions.	
(D) Repowering.	
(E) Refurbishment.	
(3) A fuel price forecast by generating unit.	Exhibit J
(4) The significant environmental effects, including:	section 3.3
(A) air emissions;	
(B) solid waste disposal;	
(C) hazardous waste; and	
(D) subsequent disposal; and	

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(E) water consumption and discharge;	
at each existing fossil fueled generating unit.	
(5) An analysis of the existing utility transmission system that includes the following:	Section 3.5
(A) An evaluation of the adequacy to support load growth and expected power transfers.	
(B) An evaluation of the supply-side resource potential of actions to reduce:	
(i)transmission losses,;	
(ii) congestion; and,	
(iii) and energy costs.	
(C) An evaluation of the potential impact of demand-side resources on the transmission network.	Section 3.4.3
(6) A discussion of demand-side resources and their estimated impact on the utility's historical and forecasted peak demand and energy.	Section 3.4.3
The information listed above in subdivision (a)(1) through subdivision (a)(4) and in subdivision (a)(6) shall be provided for each year of the future planning period.	
Sec. 6 (b) In describing possible alternative methods of meeting future demand for electric service, a utility must analyze the following resources as alternatives in meeting future electric service requirements:	
(1) Rate design as a resource in meeting future electric service requirements.	
(2) Demand-side resources	
For potential demand-side resources, the utility shall include the following:	
(A) A description of the potential demand-side resource, including its costs, characteristics and parameters.	
(B) The method by which the costs, characteristics and other parameters of the demand-side resource are determined.	
(C) The customer class or end-use, or both, affected by the demand-side resource.	
(D) Estimated annual and lifetime energy (kWh) and demand (kW) savings	
(E) The estimated impact of a demand side resource on the utility's load, generating capacity, and transmission and distribution requirements	
(F) Whether the program provides an opportunity for all ratepayers to participate, including low-income residential ratepayers.	
(3) Supply-side resources.	Section 4.5
For potential supply-side resources, the utility shall include the following:	
(A) Identification and description of the supply-side resource considered, including the following:	
(i) Size in megaatts(MW)	
(ii) Utilized technology and fuel type.	
(iii) Energy profile of non-dispatchable resources.	
(ivii) Additional transmission facilities necessitated by the resource.	
(B) A discussion of the utility's effort to coordinate planning, construction, and operation of the supply-side resource with other utilities to reduce cost.	Section 5.2.1
(C) A description of significant environmental effects, including the following:	Section 4.5
(i) Air emissions.	
(ii) Solid waste disposal.	
(iii) Hazardous waste and subsequent disposal.	
(iv) Water consumption and discharge.	
(4) Transmission facilities as resources.	Section 3.5
In analyzing transmission resources, the utility shall include the following:	
(A) The type of the transmission resource, including whether the resource consists of one of the following:	
(i) New projects	
(ii) Upgrades to transmission facilities	
(iii) Efficiency improvements; or	
(iv) Smart grid technology.	Section 3.6.1
(B) A description of the timing, types of expansion, and alternative options considered.	Section 4.1
(C) The approximate cost of expected expansion and alteration of the transmission network.	Section 3.5.9
(D) A description of how the IRP accounts for the value of new or upgraded transmission facilities increasing power transfer capability, thereby increasing the utilization of geographically constrained cost effective resources.	Section 4.1
(E) A description of how:	Section 3.5
(i) IRP data and information affect the planning and implementation processes of the RTO of which the utility is a member; and	
(ii) RTO planning and implementation processes affect the IRP.	
170 IAC 4-7-7 Selection of resources	
Sec. 7. (a) To eliminate nonviable alternatives, a utility shall perform an initial screening of the future resource alternatives listed in subsection 6(b) of this rule. The utility's screening process and the decision to reject or accept a resource alternative for further analysis must be fully explained and supported in the IRP. The screening analysis must be additionally summarized in a resource summary table	section 4.5
170 IAC 4-7-8 Resource portfolios	

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Sec. 8. (a) The utility shall develop candidate resource portfolios from existing and future resources identified in sections 6 and 7 of this rule. The utility shall provide a description of its process for developing its candidate resource portfolios, including a description of its optimization modeling, if used. In selecting the candidate resource portfolios, the utility shall at a minimum consider the following:	Section 5
(1) risk;	
(2) uncertainty;	
(3) regional resources;	
(4) environmental regulations;	
(5) projections for fuel costs;	
(6) load growth uncertainty;	
(7) economic factors; and	
(8) technological change.	
Sec. 8 (b) With regard to candidate resource portfolios, the IRP must include:	
(1) An analysis of how each candidate resource portfolio performed across a wide range of potential future scenarios, including the alternative scenarios required under subsection 4(25) of this rule.	Section 5.2.2
(2) The results of testing and rank ordering of the candidate resource portfolios by key resource planning objectives, including cost effectiveness and risk metrics.	
(3) The present value of revenue requirement for each candidate resource portfolio in dollars per kilowatt-hour delivered, with the interest rate specified.	
Sec. 8 (c) Considering the analyses of theFrom its candidate resource portfolios, a utility shall select a preferred resource portfolio and include in the IRP the following information:	Section 5.3
(1) A description of the utility's preferred resource portfolio.	
(2) Identification of the standards of reliability.	
(3) A description of the assumptions expected to have the greatest effect on the preferred resource portfolio.	
(4) An analysis showing that supply-side resources and demand-side resources have been evaluated on a consistent and comparable basis, including consideration of the following:	
(A) safety;	
(B) reliability	
(C) risk and uncertainty;	
(D) cost effectiveness; and	
(E) customer rate impacts.	
(5) An analysis showing the preferred resource portfolio utilizes supply-side resources and demand-side resources that safely, reliably, efficiently, and cost effectively meets the electric system demand taking cost, risk, and uncertainty into consideration.	
(6) An evaluation of the utility's DSM programs designed to defer or eliminate investment in a transmission or distribution facility, including their impacts on the utility's transmission and distribution system.	Section 4.4
(7) A discussion of the financial impact on the utility of acquiring future resources identified in the utility's preferred resource portfolio including, where appropriate, the following:	Section 5.3
(A) Operating and capital costs of the preferred resource portfolio.	
(B) The average cost per kilowatt-hour of the future resources, which must be consistent with the electricity price assumption used to forecast the utility's expected load by customer class in section 5 of this rule.	
(C) An estimate of the utility's avoided cost for each year of the preferred resource portfolio.	Section 4.6
(D) The utility's ability to finance the preferred resource portfolio.	Section 5.3
(8) A description of how the preferred resource portfolio balances cost effectiveness, reliability, and portfolio risk and uncertainty, including the following:	Section 5.3
(A) Quantification, where possible, of assumed risks and uncertainties, including, but not limited to:	
(i) environmental and other regulatory compliance;	
(ii) reasonably anticipated future regulations;	
(iii) public policy;	
(iv) fuel prices;	
(v) operating costs;	
(vi) construction costs;	
(vii) resource performance;	
(viii) load requirements;	
(ix) wholesale electricity and transmission prices;	
(x) RTO requirements; and	
(xi) technological progress.	
(B) An assessment of how robustness of risk considerations factored into the selection of the preferred resource portfolio.	Section 5.4
(9) Utilities shall include a discussion of potential methods under consideration to improve the data quality, tools, and analysis as part of the ongoing efforts to improve the credibility and efficiencies of their resource planning process.	Section 2
(10) A workable strategy to quickly and appropriately adapt its preferred resource portfolio to unexpected circumstances, including to the changes in the following:	

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(A) Demand for electric service.	Section 5.3
(B) Cost of a new supply-side resources or demand-side resources..	
(C) Regulatory compliance requirements and costs.	
(D) Wholesale market conditions.	
(E) Changes in fFuel costs.	
(F) Changes in eEnvironmental compliance costs.	
(G) Technology and associated costs and penetration.	
(H) Other factors which would cause the forecasted relationship between supply and demand for electric service to be in error.	
170 IAC 4-7-9 Short term action plan	
Sec. 9. (a) A utility shall prepare a short term action plan as part of itsits IRP, and shall cover a three (3) year period beginning with the first year of the IRP submitted pursuant to this rule.	Section 6.1
Sec. 9 (b) The short term action plan is a summary of the shall summarize the utility's preferred resource portfolio and its workable strategy, as described in 170 IAC 4-7-8(c)(9) of this rule,	
Sec. 9 (c) The short term action plan must include, but is not limited to, the following:	
(1) A description of resources in the preferred resource portfolio included in the short term action plan. The description may include references to other sections of the IRP to avoid duplicate descriptions. The description must include, but is not limited to, the following:	
(A) The objective of the preferred resource portfolio.	
(B) The criteria for measuring progress toward the objective.	
(2) Identification of goals for implementation of DSM programs that can be developed in accordance with IC 8-1-8.5-10, 170 IAC 4-8-1 et seq. and consistent with the utility's longer resource planning objectives.	
(3) The implementation schedule for the preferred resource portfolio.	
(4) A budget with an estimated range for the cost to be incurred for each resource or program and expected system impacts.	
(5) A description and explanation of differences between what was stated in the utility's last filed short term action plan and what actually occurred.	

Appendix Vol. 2 (See I&M IRP Web page)

Exhibit H Model Equations and Statistical Test Results

Appendix Vol. 3 (See I&M IRP Web page)(confidential exhibits or redacted versions)

Exhibit I FERC Form 715 – Confidential

Exhibit J Projected Fuel Costs – Confidential

Exhibit K Short Term Large Industrial Energy Models – Confidential

Exhibit L Long-Term Retail and Wholesale Forecast Models Data - Confidential

Exhibit M Short-Term and Long-Term Wholesale Energy Models