INTEGRATED RESOURCE PLANNING REPORT
TO THE
INDIANA UTILITY REGULATORY COMMISSION

Submitted Pursuant to
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Executive Summary

An Integrated Resource Plan (IRP or Plan) explains how an electric company anticipates meeting the projected capacity (i.e., peak demand) and energy requirements of its customers based on the information available at this time. In accordance with the Indiana Utility Regulatory Commission's (Commission) proposed IRP rule, Indiana Michigan Power Company (I&M or Company) is providing an IRP that encompasses a 20-year forecast period (2016-2035). I&M's 2015 IRP has been developed using the Company's current assumptions for:

- Customer load requirements – peak demand and energy;
- Commodity prices – coal, natural gas, on-peak and off-peak power prices, capacity and emission prices;
- Supply-side alternative costs – including fossil fuel and renewable generation resources; and
- Demand-side program costs and analysis.

This IRP also factored in a prudent bias to continue I&M's progress toward even lower emission generation. The traditional financial evaluation of the options indicated that I&M could accelerate the installation of renewable resources without an inordinate impact on customer rates. It also indicated that the lower cost of retaining both Rockport units over retiring one of the Rockport units prior to 2035 was highly dependent on assumptions and varied from near break-even to over $300M in cost savings in the scenarios which were evaluated. As the IRP is regularly updated, I&M will continue to examine paths to reduce emissions while maintaining reliability and retaining a low cost advantage for customers.

To meet customers' future energy requirements, I&M has carefully considered the continued operation and the ongoing level of investment in its existing fleet of assets including its efficient base-load coal plant (Rockport Units 1 and 2), and its nuclear facility, the Donald C. Cook Nuclear Plant (Cook Plant). Another consideration in this 2015 IRP is the increased adoption of distributed rooftop solar resources by I&M's customers. While I&M does not control the extent this resource is deployed, it recognizes that distributed solar will likely offset a portion of I&M's resource requirements. Keeping these considerations in mind, I&M has developed a plan to provide adequate supply and demand resources to meet its peak load obligations for the next twenty years.

The key components of this plan are for I&M to:

- Invest in environmental control equipment to allow Rockport Units 1 and 2 to continue compliant operation under known or anticipated environmental regulations
- Continue operation of the Cook Plant through, minimally, the remainder of its current license periods
- Add 1,235MW of Natural Gas Combined Cycle (NGCC) generation in 2035 to replace Cook Unit 1, assuming it is retired in 2034
- Add 600MW (nameplate) of utility owned solar resources beginning with 20MW in 2020 and an additional 30MW in 2021
- Add 1,350MW (nameplate) of wind resources beginning with 150MW in 2020
- Implement demand-side resources in the form of additional energy efficiency programs
- Recognize that residential and commercial customers will add distributed resources, primarily in the form of residential and commercial rooftop solar

It is important to note that I&M's IRP is based upon the best available information at the time of preparation. Because changes that may impact this Plan can, and do, occur without notice, this Plan is not a commitment to a specific course of action. The future is highly uncertain, particularly in light of current economic conditions, access to capital, the increasing use of renewable generation and end-use efficiency, as well as current and future laws and environmental regulations, including the U.S. Environmental Protection Agency's (EPA) Clean Power Plan (CPP). The implementation action items as described in the Plan are subject to change as new information becomes available or as circumstances warrant.

Environmental Compliance Issues

I&M's 2015 IRP considers the impacts of final and proposed EPA regulations to I&M generating facilities. Environmental compliance requirements have a major influence on the consideration of new supply-side resources for inclusion in the IRP because of the potential significant effects on both capital and operational costs. In addition, the IRP development process assumes potential regulation of Greenhouse Gases (GHG)/carbon dioxide (CO_2). For that purpose, a reasonable proxy was utilized in the IRP that assumed that the resulting economic impact would be equivalent to a CO_2 "tax" applicable to each ton of carbon emitted from fossil-fired generation sources which would take effect beginning in 2022. Under the Company's Base pricing scenario, the cost of such CO_2 emissions is expected to stay within the $15-$20/metric ton (tonne) range over the long-term analysis period.

The Clean Power Plan

On August 3, 2015, the EPA finalized a rule referred to as the CPP, which establishes CO_2 emission guidelines for existing fossil generation sources under Section 111(d) of the Clean Air Act.

I&M is currently in the process of reviewing these rulemakings and must undertake significant new analyses to understand the impacts of the Final CPP. I&M, its parents company American Electric Power (AEP), and other stakeholders will be working in the coming months and years to better understand the requirements of the Final CPP, to work with state agencies to develop reasonable implementation plans, and then to plan for compliance with the final approved plan.

Indiana IRP Stakeholder Process

This is the second I&M IRP to be developed under the Commission's proposed IRP rule and is the result of analyses performed by I&M that includes consideration of stakeholder input. I&M initiated a stakeholder public advisory process in February 2015 in order to provide an opportunity for public participation in the IRP development process. I&M provided electronic notice and invitations to participate in the stakeholder process to the Indiana Commission Staff, the 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 2013 IRP public advisory process. I&M also provided invitations to participate to its top thirty largest commercial and industrial customers. 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 2013 IRP, 2015 registration information, meeting documents and agendas.

Stakeholders were presented information at Stakeholder meetings in March and June of 2015 and, based on those sessions, provided useful feedback which has been considered and incorporated in the analysis, where warranted. The feedback included suggestions such as modeling of the following: additional Combined Heat and Power (CHP) resources, removing constraints on solar and wind additions, lowering solar cost options by extending the Investment Tax Credit (ITC), adding a carbon free portfolio model run, modeling extreme weather events, and evaluating the closing of existing fossil-fuel resources earlier than their estimated useful life. This feedback was used by I&M to modify the suite of cases that were analyzed. I&M addressed additional stakeholder comments pertaining to energy efficiency, CO_2 cost estimates, load assumptions, distributed generation assumptions and provided general transparency to its assumptions and modeling energy efficiency programs on the same basis as supply resources. In addition, stakeholders and Staff filed comments on I&M's previous IRP report issued in November 2013. I&M considered all stakeholder input collected throughout the process. A summary of stakeholder input and how it was considered in the IRP process is included in Exhibit E of the Appendix.

Key dates for the IRP public advisory process are shown below in Table ES-1:

Table ES-1. Key IRP Public Advisory Process Dates

EVENT	DATE
I&M holds first Stakeholder meeting	March 2015
Stakeholder and Staff comments received	April 2015
Stakeholder conference call	May 2015
I&M holds second Stakeholder meeting	June 2015
Stakeholders file comments	July 2015
I&M holds final Stakeholder meeting	September 2015
Final Stakeholder comments received	October 2015
IRP Filed	November 2015
Director's report	Spring 2016

Summary of I&M Integrated Resource Plan

I&M's total internal energy and peak demand requirements are forecasted to increase at a Compound Average Growth Rate (CAGR) of 0.2% over the IRP planning period (through 2035). The net impact of load growth and plant capacity rating changes leaves I&M with a "going-in" (i.e. *before* resource additions) capacity position as shown in Figure ES-1. As can be seen from Figure ES-1, in 2030 I&M is anticipating a capacity deficit, which is evident from the gap between stacked bar of available resources and the black line representing I&M's load demand plus PJM reserve requirements.

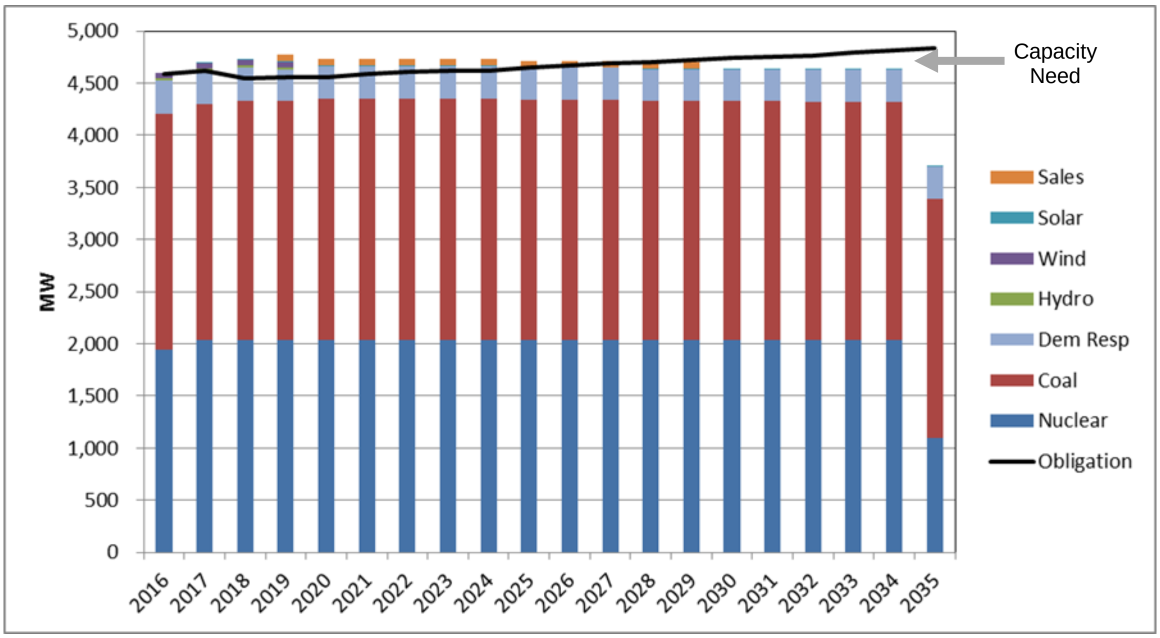

Figure ES-1. I&M 2016 "Going-In" PJM Capacity Position

To determine the appropriate level and mix of incremental supply and demand-side resources required to offset such going-in capacity deficiencies, I&M utilized the *Plexos*® Linear Program (LP) optimization model to develop a "least-cost" resource plan. The greatest variables in I&M's planning process involve decisions on the current lease agreement of Rockport Unit 2, and potential installation of Flue Gas Desulfurization (FGD) equipment on both of the Rockport units. Accordingly, I&M also evaluated cases which removed one *or both* Rockport units. Although the IRP planning period is limited to 20 years (through 2035), the *Plexos*® modeling was performed through the year 2045 so as to properly consider various cost-based "end-effects" for the resource alternatives being considered.

I&M used the results of the modeling to develop a "Preferred Portfolio".

I&M's Preferred Portfolio

- Maintains I&M's two units at Rockport Plant, including the addition of Selective Catalytic Reduction (SCR) systems in 2017 and 2019; as well as FGD systems in 2025 and 2028
- Continues operation of I&M's carbon free nuclear plant through, minimally, its current license extension period
- Add 600MW (nameplate) of large-scale solar resources
- Add 1,350MW (nameplate) of wind resources
- Adds 1,253MW of NGCC generation in 2035
- Implements end-use energy efficiency programs so as to reduce energy requirements by 914GWh and capacity requirements by 70MW in 2035
- Adds 27MW of natural gas CHP generation
- Recognizes additional distributed solar capacity will be added by I&M's customers, starting in 2016, and ramping up to 5MW (nameplate) by 2035

To arrive at the Preferred Portfolio composition, I&M developed *Plexos*®-derived, "optimum" portfolios for five separate cases under five commodity pricing conditions, in addition to "high-load" and "low-load" forecast sensitivities, as well as a unique sensitivity addressing the installation of an SCR on Rockport Unit 2. The Preferred Portfolio was ultimately derived from the optimum "Steady State" portfolio, which reflected the continued operation of both Rockport units through the 20-year planning period. The Preferred Portfolio added levels of CHP, wind and solar resources beginning in 2020, with such renewable resources incorporated sooner than indicated by the optimized modeling results. While not representing a 'least-cost' solution, the Preferred Portfolio provides a resource plan with reasonable costs while; 1) meeting the incremental (peak) demand and energy of I&M's customers; 2) increasing resource/fuel diversity; 3) managing the risks of I&M's baseload generation fleet; 4) achieving expected environmental and resource adequacy constraints; and 5) offering I&M potential optionality around future prospects for CO_2 regulation. The following Table

ES-2 provides a summary of the I&M Preferred Portfolio.

Table ES-2. Preferred Portfolio Cumulative Capacity Additions over Planning Period (2016-2035)

Indiana Michigan Power Company
2015 Integrated Resource Plan
Cumulative Resource Changes

Preferred Portfolio

MW		(1) (Cumulative) Existing Fleet	(2) (Cumulative) Firm Capacity Resource ADDITIONS: New-Build		(4)	(6) Energy Efficiency (EE)	(7)	(8)	(9) EECO	(10) DR	(11) Wind [(D)]	(12) Solar [(E)]	(13)	(14)=(1)to(13), ex(6, 10)	(15) Resulting I&M Reserves Above	(16)	(17) (Cumulative) 'NAMEPLATE' ADDITIONS: Wind [(D)]	(18) Solar [(E)]	(19)
IRP Period	PJM Planning Year [(A)]	Unit Uprates, Derates, and PJM Capacity Performance Impact	NG CTs	NG Combined Heat and Power	NGCC	'Embedded' Federal EE Regulations (Non-DSM EE) [(B)]	Current DSM Programs [(C)]	New	New	Pre-Existing DR Programs [(C)]		Utility Scale	Distributed	(Cumul.) NET 'RESOURCE' CHANGE [(P)]	PJM Minimum Rqrmnt [(Q)]	PJM Reserve Margin %	No (PJM) capacity value assumed	Utility Scale	Distributed
Yr.		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW		MW	MW	MW
1	2016	-	-	-	-	206	26	-	6	298	No PJM Capacity value - see nameplate additions column	-	-	33	13	0.3%	-	-	-
2	2017	98 [(F)]	-	-	-	206	37	-	6	298		-	-	141	82	2.1%	-	-	-
3	2018	129 [(G)]	-	-	-	205	37	8	6	298		-	0.4	181	196	5.0%	-	-	1.0
4	2019	197 [(H)]	-	-	-	204	37	16	6	298		-	0.4	257	239	6.1%	-	-	1.0
5	2020	151 [(I)]	-	14	-	206	37	18	6	298		8	0.4	234	214	5.5%	150	20	1.0
6	2021	151	-	14	-	211	37	19	6	298		19	0.4	247	195	4.9%	150	50	1.0
7	2022	151	-	14	-	218	37	21	6	298		19	0.4	248	177	4.5%	150	50	1.0
8	2023	151	-	14	-	226	37	23	6	298		19	0.8	250	163	4.1%	150	50	2.0
9	2024	151	-	14	-	234	37	23	6	298		19	0.8	251	157	3.9%	300	50	2.0
10	2025	137 [(J)]	-	14	-	243	37	25	6	298		38	0.8	258	132	3.3%	450	100	2.0
11	2026	137	-	27	-	252	37	27	6	298		57	0.8	292	144	3.6%	600	150	2.0
12	2027	137	-	27	-	260	37	28	6	298		76	1.1	313	142	3.5%	750	200	3.0
13	2028	122 [(K)]	-	27	-	268	37	30	6	298		95	1.1	319	134	3.3%	900	250	3.0
14	2029	123	-	27	-	277	37	32	6	298		114	1.1	340	130	3.2%	1,050	300	3.0
15	2030	61 [(L)]	-	27	-	288	37	32	6	298		133	1.1	298	69	1.7%	1,200	350	3.0
16	2031	61	-	27	-	299	37	32	6	298		152	1.5	318	71	1.7%	1,350	400	4.0
17	2032	59	-	27	-	309	37	33	6	298		171	1.5	335	81	2.0%	1,350	450	4.0
18	2033	59	-	27	-	319	37	33	6	298		190	1.5	354	67	1.6%	1,350	500	4.0
19	2034	59	-	27	-	328	37	33	6	298	-	209	1.9	374	71	1.7%	1,350	550	5.0
20	2035	(872) [(M)]	-	27	1,253	399	37	34	6	298		228	1.9	715	391	9.4%	1,350	600	5.0
						328	70											605	
						'TOTAL' Energy Efficiency (2016-2035)												TOTAL' Solar (2016-2035	

[(A)] PJM Planning Year is effective 6/1/XXXX.

[(B)] Represents estimated energy efficiency levels already 'embedded' into I&M's long-term load & peak demand forecast based on emergence of PRIOR-ESTABLISHED Federal efficiency standareds (EPAct 2005; 2007 EISA, 2009 ARRA).

[(C)] Represents estimated contribution from current/known I&M DSM-EE and Demand Response (Interruptible, DLC/ELM) program activity also reflected in the Company's long-term load and demand forecast *(from CLR input sheet)*.

[(D)] Due to the intermittency of wind resources, I&M assumes 0% of nameplate' MW rating are included for capacity resource determination purposes beyond 2020.

[(E)] Due to the intermittency of solar resources, Utility and Distributed Solar receive 38% of nameplate MW rating for capacity resource determination purposes.

Changes to existing resources Post-June 1, 2015:
[(F)] Cook Unit 2 turbine Upgrade and rating adjustment
[(G)] Rockport 1 turbine upgrade.
[(H)] PJM EE nomination begins.
[(I)] Rockport 2 turbine upgrade offset by removal of wind/hydro for PJM CP.
[(J)] Rockport 1 FGD derate
[(K)] Rockport 2 FGD derate
[(L)] PJM EE Nomination ends
[(M)] Cook 1 Retires

[(P)] Includes changes in existing resources plus plan additions, excluding "embedded" EE and existing DR programs.

[(Q)] PJM minimum criterion @15.7% as a function of peak demand.

The Preferred Portfolio compares favorably with the "Fleet Modification" portfolio, which assumes one Rockport unit is removed from I&M's fleet in 2022 and is replaced with natural gas combined cycle capacity. The Fleet Modification Portfolio is somewhat more expensive than the Steady State portfolio in four of five pricing scenarios, and slightly less expensive in one pricing scenario.

Specific I&M capacity and energy production changes over the 20-year planning period associated with the Preferred Portfolio are shown in Figure ES-2 through Figure ES-5, below. Figure ES-2 and Figure ES-3 indicate that this Preferred Portfolio would reduce I&M's reliance on coal and nuclear-based generation as part of its portfolio of resources, and increase reliance on renewable resources, thereby enhancing fuel diversity. Specifically, over the 20-year planning horizon, the Company's capacity mix attributable to coal-based assets would decline from 48% to 40%; while nuclear assets would be anticipated to decline from 42% to 19% (under the assumption that one of the Cook units would be retired in 2034 at the end of its current license). To offset those reductions, in addition to new NGCC resources (7%), renewable resources (wind, solar, and hydro--based on nameplate ratings) would be anticipated to increase from 10% to 33%, and, similarly, demand-side and energy-efficiency measures increase from 1% to 2% over the planning period. Figure ES-4 and Figure ES-5 show I&M's energy output attributable to coal-based assets decreases from 40% to 33%; while nuclear generation shows a decrease from 53% to 38% over the period. Likewise, in addition to new NGCC (15%), renewable energy would be anticipated to increase from 6% to 13% over the planning period.

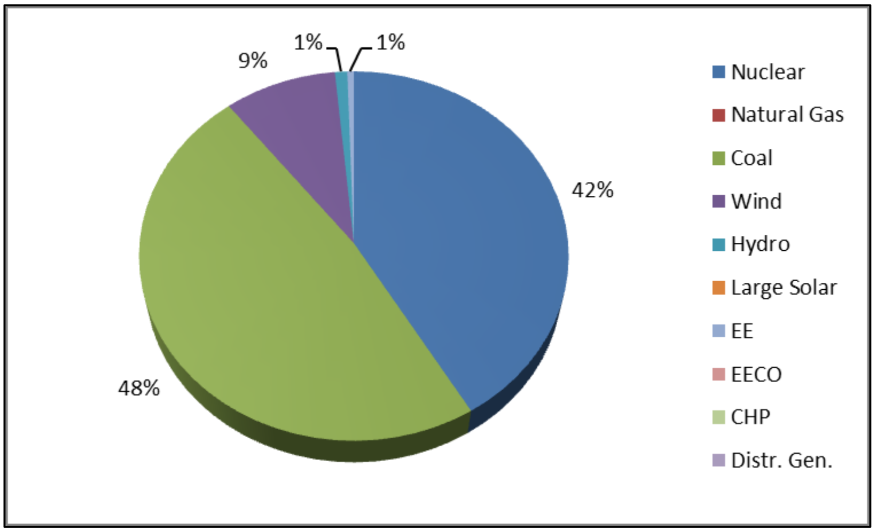

Figure ES-2. 2016 I&M Nameplate Capacity Mix

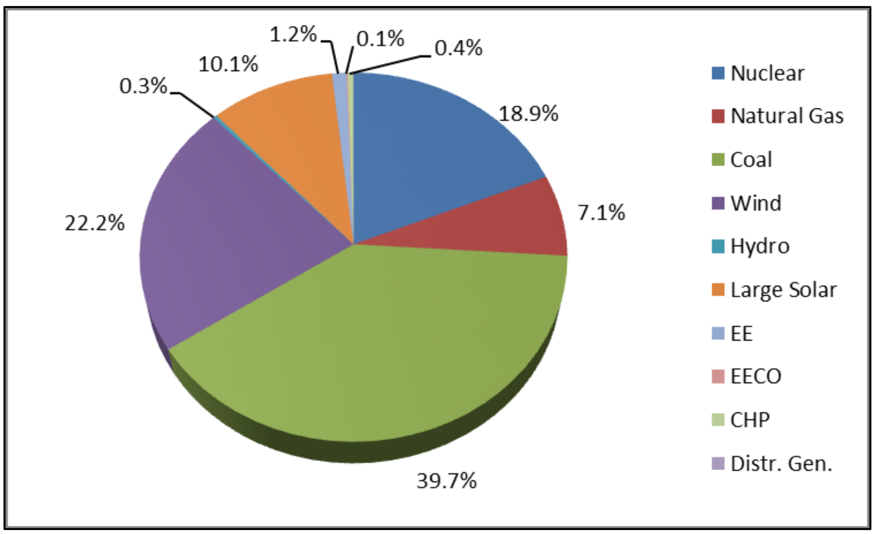

Figure ES-3. 2035 I&M Nameplate Capacity Mix

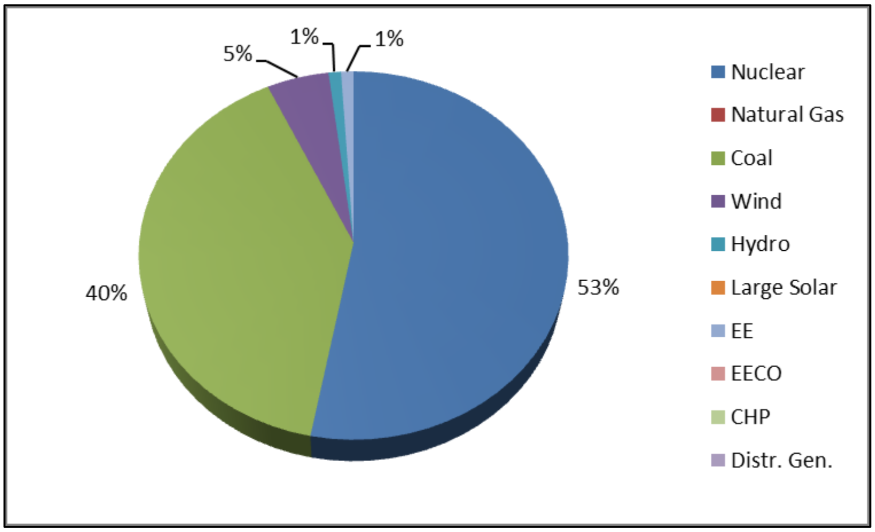

Figure ES-4. 2016 I&M Energy Mix

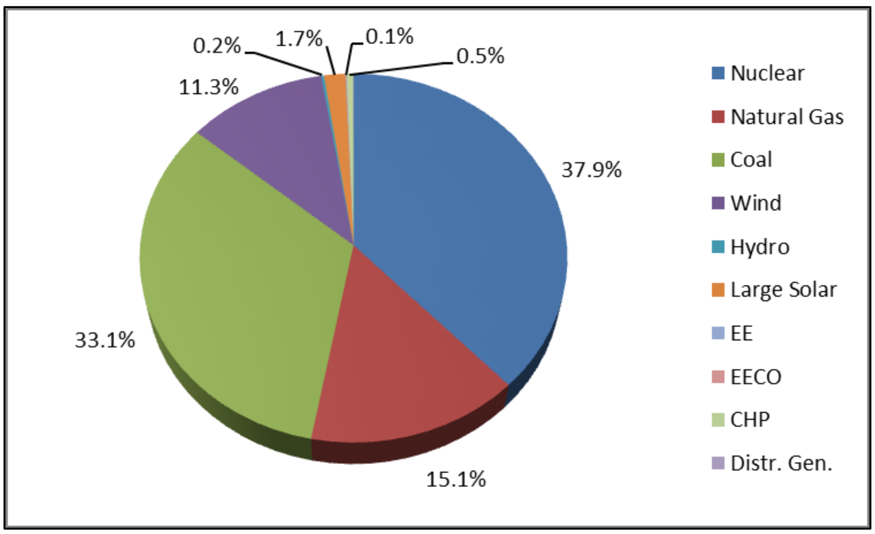

Figure ES-5. 2035 I&M Energy Mix

Figure ES-6 illustrates I&M's annual capacity position with respect to the Company's load obligation factoring in PJM's capacity margin requirement, after incorporation of the Preferred Portfolio. Due to its intermittent nature, as well as the emerging PJM "Capacity Performance" reliability construct, the ultimate *capacity* contribution from renewable resources is assumed to be fairly modest. However, such renewable resources can contribute a significant volume of *energy* resources, I&M's

Plexos® optimization modeling selected these wind and solar resources because they were projected to add more relative value (*i.e.*, lowered I&M's net energy cost) than alternative resources examined, including the purchase of energy from the PJM market.

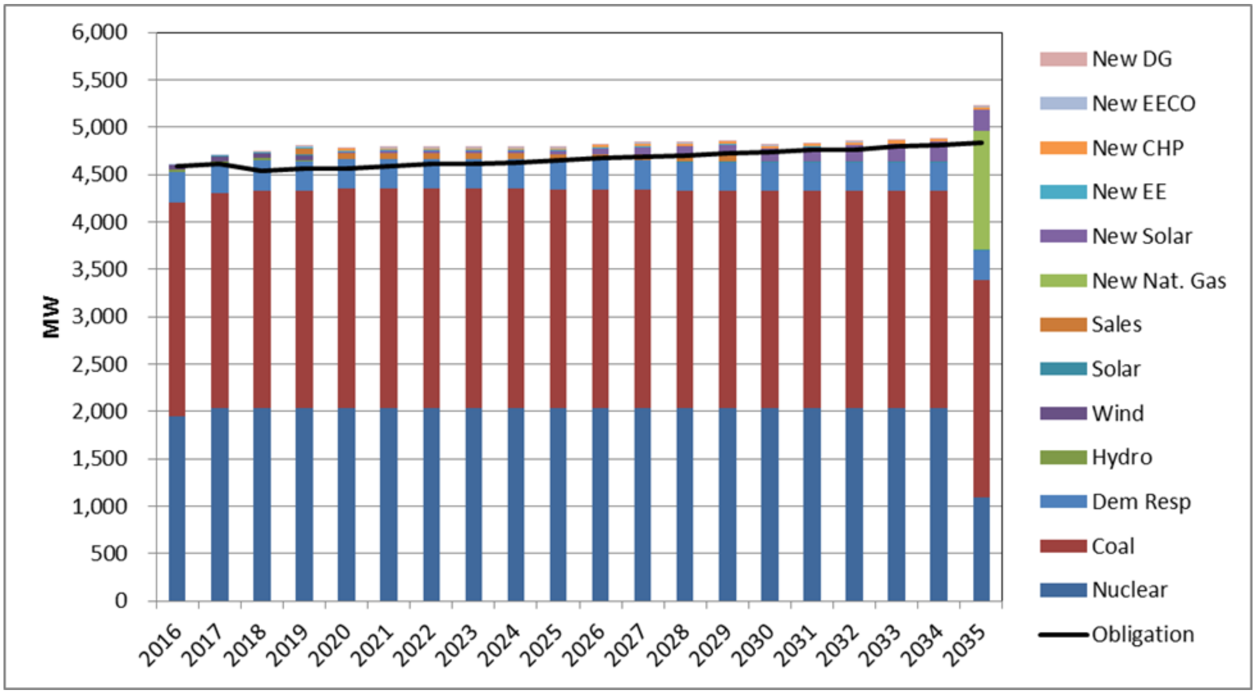

Figure ES-6. I&M Preferred Portfolio PJM Capacity Position through Planning Period (2016-2035)

I&M Short-Term Action Plan

I&M's Short-Term Action Plan applies to the period beginning November 2015 and ending December 2018. 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.

Steps to be taken by I&M in the near future to implement this plan include:

1. Continue the planning and regulatory actions necessary to manage and implement economic energy efficiency programs in Indiana and Michigan. This primarily consists of efficient administration and implementation, managing performance, reporting and evaluating current programs, and assessing market conditions through a forward-looking market potential study for the Company.

2. Continue to evaluate the Final EPA CPP guidelines and provide technical input to state regulatory bodies regarding cost effective compliance options based on on-going activity.

In addition to the steps pertaining to the short-term action plan, I&M will continue to implement plans associated with the following:

- Cook Plant's Life-Cycle Management (LCM) program
- Engineering, design and construction associated with the Rockport Unit 1 SCR, to be completed and in-service in 2017
- Completing construction and commissioning of the pilot solar project.

The Short-Term Action Plan will require I&M to make investments to accomplish Item 1 shown above, the estimated expenditures for 2016 and 2017 are in the range of $20 million per year with coincident capacity savings of approximately 12MW in 2016 and 10MW in 2017 and energy savings of 175GWh per year. For 2018, the Preferred Portfolio suggests investments of approximately $23 million with an estimated coincident capacity savings of 8MW and energy savings of 175GWh. At this time, I&M does not have an estimate to evaluate the Final CPP guidelines.

I&M accomplishments related to the 2013 IRP Short Term Action Plan include the following items that have been either completed or are on schedule for completion:

- Acquired 200MW of Wind resources through the Headwaters project;
- Initiated and received approval to build a 14.7MW Solar Pilot Program, which will allow I&M to improve the overall understanding and integration of solar technology as a system resource;
- A DSI system has been installed at the Rockport Plant to meet the HCl limit under the MATS Rule;
- As of June 2015, completed 37 Cook Plant LCM related activities

- Continued to implement demand-side management programs, began a transition to utility administered programs based on I&M demographic attributes and characteristics, and introduced two new programs including I&M's Electric Energy Consumption Optimization program
- Tanners Creek units 1-4 have been removed from service

Conclusion

This IRP provides for reliable electric utility service, at reasonable cost, through a combination of renewable supply-side resources and demand-side programs and serves as a roadmap for I&M to provide adequate capacity resources to serve its customers' peak demand and required PJM reserve margin needs throughout the forecast period.

The highlighted Preferred Portfolio offers incremental resources that will provide—in addition to the needed PJM installed capacity to achieve mandatory PJM (summer) peak demand requirements—additional carbon-free energy so as to hedge against PJM energy markets that could be influenced by many external factors, including the impact of carbon, going-forward.

The IRP process is a continuous activity; assumptions and plans are continually reviewed as new information becomes available and modified as appropriate. Indeed, the capacity and energy resource plan reported herein reflects, to a large extent, assumptions that are subject to change; it is simply a snapshot of the future at this time. This IRP is not a commitment to a specific course of action, as the future is highly uncertain. The resource planning process is becoming increasingly complex when considering pending regulatory restrictions, technology advancement, changing energy supply pricing fundamentals, uncertainty of demand and energy efficiency advancements. These complexities necessitate the need for flexibility and adaptability in any ongoing planning activity and resource planning processes. Last, the ability to invest in capital-intensive generation infrastructure is increasingly challenged in light of current economic conditions and the impact of all these factors on I&M's customers are a primary consideration in this report.

1.0 Introduction

1.1 Overview

This report presents the Integrated Resource Plan (IRP) for Indiana Michigan Power Company (I&M, or "Company") including descriptions of assumptions, study parameters, and methodologies. The results incorporate the integration of supply-side resources and demand-side management (DSM) activity.

*The goal of the IRP process is to identify the **amount**, **timing** and **type** of resources required to ensure a reliable supply of power and energy to customers at the least reasonable cost.*

In addition to developing a long-term strategy for achieving reliability/reserve margin requirements as set forth by I&M's Regional Transmission Organization (RTO), PJM, capacity resource planning is critical to I&M due to its impact on:

- **Determining Capital Expenditure Requirements**—which represents one of the basic elements of the Company's long-term business plan.
- **Rate Case Planning**—operating in two state retail jurisdictions as well as having wholesale contracts which fall under the auspices of the Federal Energy Regulatory Commission (FERC), this planning process is a critical component of recovery filings that will reflect input based on a prudent planning process.
- **Integration with other Strategic Business Initiatives**—generation/capacity resource planning is naturally integrated with the Company's current and anticipated environmental compliance, transmission planning, and other corporate planning initiatives.

1.2 IRP Process

This IRP briefly covers the processes and assumptions required to develop the recommended Plan for I&M. The IRP process consists of the following components/steps:

- Description of the Company, the resource planning process in general, and the implications of current issues as they relate to resource planning.
- Provide projected growth in peak load and energy which serves as the underpinning of the plan.
- Identify and evaluate demand-side options such as energy efficiency measures, demand response and distributed generation.
- Identify current supply resources, including projected changes to those resources (*e.g.,* de-rates or retirements), and transmission system integration issues.
- Identify and evaluate supply-side resource options.

- Describe the analysis and assumptions that will be used to develop the plan such as RTO reserve margin criteria, and fundamental modeling parameters.
- 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.
- Develop an action plan to be used in implementing the IRP during the first three years of the planning horizon.
- Present the draft findings and recommendations to stakeholders, receive and consider their input, then develop the final preferred portfolio, and near term action plan.

1.2.1 Indiana IRP Stakeholder Process

This report is the second I&M IRP to be developed under the State of Indiana's proposed IRP rules and is the result of analysis performed by I&M that includes consideration of stakeholder input. Various stakeholders, including Indiana Utility Regulatory Commission (IURC, or "Commission") staff, participated extensively throughout the IRP development process.

I&M initiated a stakeholder public advisory process in February 2015 in order to provide an 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 (OUCC), the interveners in I&M's most recent general rate case in Indiana and stakeholders that participated in I&M's 2013 IRP public advisory process. I&M also provided invitations to its thirty largest commercial and industrial customers. 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 2013 IRP, 2015 registration information and other materials.

At I&M's introductory meeting held in March 2015, stakeholders were presented with basic IRP planning information, I&M's IRP study plan and assumptions and were asked to provide comments on portfolio components, resource attributes, and economic scenarios and risk considerations. A follow-up stakeholder conference call was held in May 2015 to review stakeholder comments and the associated modeling and study implications. I&M worked with participating stakeholders to establish the venue for the second public advisory meeting workshop location. The second workshop and third stakeholder outreach meeting was held in late June to review modeling results and collect additional feedback. The June workshop included a review of the items covered in the first stakeholder meeting and a follow-up call and further addressed the topics of load forecast, evaluation of existing resources, evaluation of supply and demand side resources, treatment of risk and uncertainty. The final stakeholder workshop was held in September to review the material covered in the previous stakeholder meetings, to present the near-final modeling results and to obtain final stakeholder input. At this meeting, I&M discussed the rationale for determining the preferred resource portfolio.

The stakeholder participants and Commission staff provided useful feedback throughout the process, which has been considered and incorporated, where warranted. For example, comments regarding case components were used by I&M to modify the suite of cases that were analyzed, including the addition of a "carbon free" and multiple "Rockport unit retirement" cases. Also, I&M addressed stakeholder comments pertaining to Energy Efficiency (EE) by providing transparency to its assumptions and modeling EE programs on the same basis as supply-side resources. The presentation materials from each stakeholder meeting were maintained throughout the process on the I&M IRP webpage. 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 holds first Stakeholder meeting	March 2015
Stakeholder and Staff comments received	April 2015
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Director's report	Spring 2016

A summary of stakeholder input and how I&M considered the input in the IRP process is included in Exhibit E of the Appendix. Stakeholder input generally fell into one of three categories: requests for additional information; suggested portfolio configurations; and resource attributes or pricing assumptions. I&M provided responses to requests for additional information at subsequent stakeholder meetings or in this report where practical. I&M has made a good-faith effort to be open and transparent regarding input assumptions and modeling results. Comments regarding portfolio configurations generally sought the evaluation of portfolios that excluded one or both Rockport units, and/or included higher levels of renewable resources than the Company's model optimally selected. Again, I&M developed portfolios that were responsive to these suggestions and used data from these portfolio evaluations to guide its development of the Preferred Portfolio. Stakeholder input regarding resource attributes or pricing assumptions were also helpful to I&M in developing its Preferred Portfolio. Specifically, I&M did not originally include a Combined Heat and Power (CHP) resource as an option. After receiving stakeholder input, I&M began modeling a CHP resource and ultimately included CHP resources in the Preferred Portfolio.

After the second stakeholder meeting I&M received input encouraging I&M to plan to reduce coal burning by at least half by 2020 and to expand its EE programs in Indiana to reduce demand. After the final stakeholder meeting, I&M received similar comments in the form of a petition requesting I&M to reduce coal generation, expand EE, and encourage development of renewable energy resources in the communities it serves. In addition, the Indiana National Association for the Advancement of Colored People (NAACP) submitted four questions regarding outreach to populations most impacted by the IRP and DSM decisions, the difference in job creation between the Preferred Portfolio and an alternative carbon free plan, the impact of the U.S. Environmental Protection Agency's (EPA) Clean Power Plan (CPP) on the Preferred Portfolio, and social corporate responsibilities I&M considers when developing its IRP.

I&M recognizes the passion surrounding these issues, some of which are related to the IRP development and some of which go beyond the focus of resource planning. I&M continues to be an industry leader in responsible and reasonable environmental investments. Stakeholders often ask if the cost of carbon has been factored into I&M's resource planning process. The potential for carbon regulation has been part of the integrated resource planning process and is continuously evolving as more definitive requirements emerge from Congress and federal regulators. I&M's planning process considers all available resource and market options to achieve the most economical outcome for customers. Quantification and support can be found later in this IRP report or in American Electric Power's (AEP) Sustainability Report located on AEP.com.

Between 1998 and 2013, I&M's parent company AEP reduced its carbon dioxide emissions by 33 percent. AEP expects emissions to continue declining in the coming years due to the use of less coal and increases in the use of natural gas to generate electricity. In the future I&M's generating capacity will consist of nuclear, hydro and renewables, in addition to the coal. I&M will also use EE and Demand Response (DR) programs to help customers manage their energy use.

As part of the AEP System, I&M has also proactively supported a number of climate change public policy initiatives and made significant investments in clean-coal technologies, including advancing the world's first integrated carbon dioxide (CO_2) capture and storage project. AEP continues to investigate technologies that can supply affordable and reliable electricity while reducing the environmental impact of the power generation process. AEP is also expanding its transmission infrastructure to allow greater integration of renewable and other intermittent, non-emitting resources on the grid.

I&M is currently in the process of reviewing the CPP rulemakings and must undertake significant new analyses to understand the impacts of the final CPP. I&M, AEP, and other stakeholders will be working in the coming months and years to better understand the requirements of the Final CPP and to work with state agencies on the state's response to the final CPP.

I&M serves a diverse set of customers that judge their experience in terms of cost, quality and service. A balanced approach is required in providing reliable, quality and affordable service.

1.3 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 586,000 retail customers in those states; including over 458,000 and 128,000 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 historical 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 (2015) actual I&M summer and winter peak demands were significant at 4,398MW and 3,952MW, occurring on July 28th and January 14th, respectively.

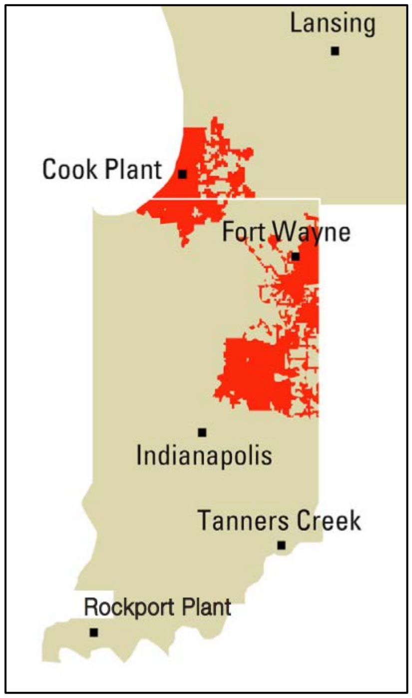

Figure 1. I&M Service Territory

This IRP is based upon the best available information at the time of preparation. However, changes that may impact this plan can, and do, occur without notice. Therefore this plan is not a commitment to a specific course of action, since the future, now more than ever before, is highly uncertain, particularly in light of economic conditions, access to capital, the movement towards increasing use of renewable generation and end-use efficiency, as well as legislation to control greenhouse gases (GHGs).

The implementation action items as described herein are subject to change as new information becomes available or as circumstances warrant.

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 2015.[1] 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 (2016-2035)[2], I&M's service territory is expected to see population and non-farm employment growth of 0.2% and 0.1% 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 0.2% per year with stronger growth expected from the industrial class (+0.4% per year) while the residential class experiences a decline (-0.2% per year) over the forecast horizon. Finally, I&M's internal energy and peak demand are expected to increase at an average rate of 0.1% and 0.2% per year, respectively, through 2035.

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 January 2015. Moody's Analytics projects moderate growth in the U.S. economy during the 2016-2035 forecast period, characterized by a 2.0% annual rise in real Gross Domestic Product (GDP), and moderate inflation as well, with the implicit GDP price deflator expected to rise by 2.1% per year.

[1]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.

[2] 20 year forecast periods begin with the first full forecast year, 2016.

Industrial output, as measured by the Federal Reserve Board's (FRBs) index of industrial production, is expected to grow at 1.3% per year during the same period. Moody's projected employment growth of 0.1% per year during the forecast period and real regional income per-capita annual growth of 1.5% 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 energy efficiency 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 of 2007, etc.) modeled by the EIA. In addition to general trends in appliance efficiencies, the Company also promotes various (DSM) programs that the Commission approves as part of its DSM portfolio. The load forecast utilizes the most current Commission approved filing at the time the load forecast is created to adjust the forecast for the impact of these programs.

2.3 Overview of Forecast Methodology

I&M's load forecasts are based mostly on econometric, state-of-the-art 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, below.

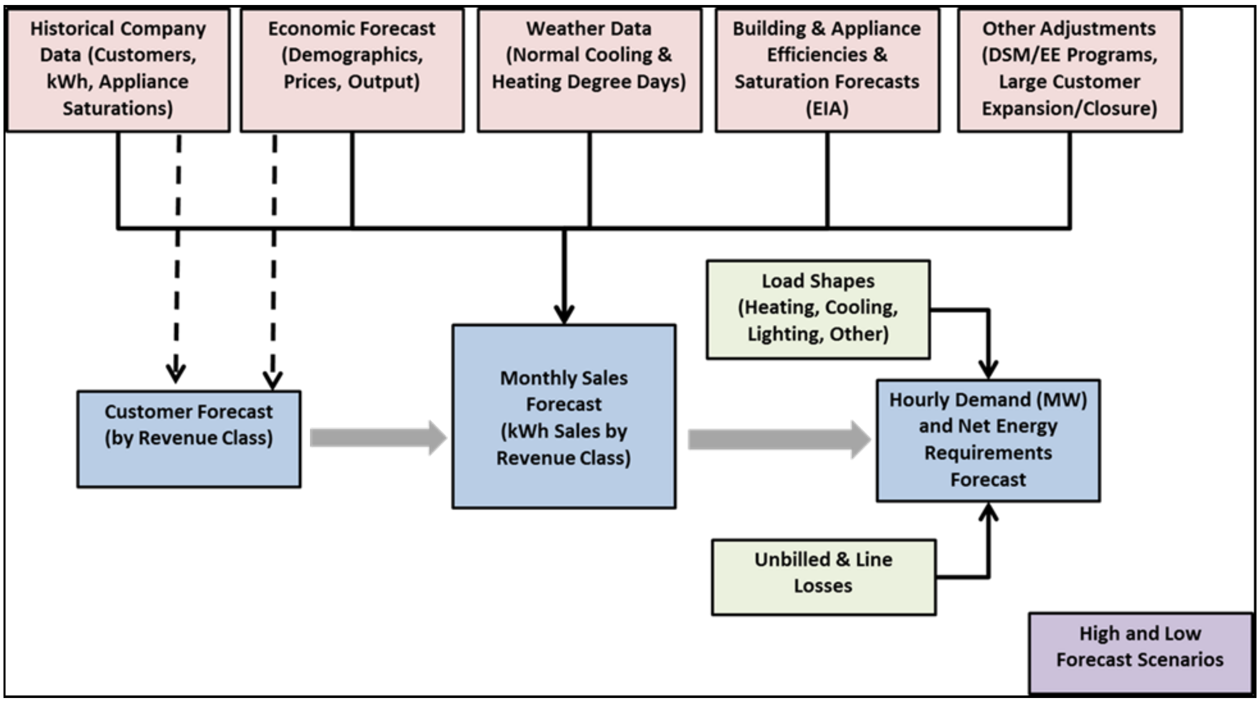

Figure 2. I&M Internal Energy Requirements and Peak Demand Forecasting Method

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.

Relative energy prices also have an 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 impact 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.

2.4.2 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 30 years. The explanatory economic and demographic variables include gross regional product, employment, population and housing stock are used in various combinations for each jurisdiction. 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.

2.4.3 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.

There are separate models for the Indiana and Michigan jurisdictions of the Company. The estimation period for the short-term models was January 2005 through January 2015. There are models for residential, commercial, industrial, other retail, and wholesale sectors. The industrial models are comprised of 20 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 part of the IRP process.

2.4.4 Long-term Forecasting Models

The goal of the long-term forecasting models is to produce a reasonable load outlook for up to 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 1995-2014 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.

2.4.4.1 Supporting Models

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

2.4.4.1.1 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 "2015 Annual Energy Outlook." The natural gas price model is based upon 1980-2014 historical data.

2.4.4.2 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 models are estimated using linear regression models. These monthly models are typically for the period January 1995 through January 2015. It is important to note, as will be discussed later in this document, that this modeling *has* incorporated the reductive effects of the EPAct, the Energy Independence and Security Act of 2007 (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.

2.4.4.3 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 similar to the residential SAE models.

2.4.4.4 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 are special occurrences and are incorporated into the models. Based on information from customer service engineers they 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 2015.

2.4.4.5 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 of new customers.

2.4.5 Internal Energy Forecast

2.4.5.1 Blending Short and Long-Term Sales

Forecast values for 2015 and 2016 are taken from the short-term process. Forecast values for 2017 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 2017 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.

2.4.5.2 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.

2.4.5.3 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 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.

2.4.6 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 of the report can be found in the Appendix of this report in Exhibit A.

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 2005-2014, 2015 data are six months actual and six months forecast and on a forecast basis for the years 2016-2035. 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. Forecast composition of other internal energy sales are provided on Exhibit A-3.

2.5.2 Peak Demand and Load Factor

Exhibit A-4 provides I&M's seasonal peak demands, annual peak demand, internal energy requirements and annual load factor on an actual basis for the years 2005-2014, 2015 data are six months actual and six months forecast and on a forecast basis for the year 2016-2035. The table also shows annual growth rates for both the historical and forecast periods.

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 2005, 2007, 2009, 2011, 2013 and 2015 (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 2005 and 2010, and as forecasted for 2015 (includes actual data through June), 2025 and 2035. Exhibit A-7 shows, for the winter-peak month and summer-peak month for the years 2009 and 2014, 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 2015 and 2025, I&M's–East Zone 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 2014 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, 2005-2014.

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 3 presents I&M's historical and forecasted residential and commercial usage per customer between 1991 and 2020. During the first decade shown (1991-2000), residential usage per customer grew at an average rate of 0.4% per year while the commercial usage grew by 0.6% per year. Over the next decade (2001-2010), growth in residential usage growth continued to be 0.4% per year while the commercial class usage decreased by 0.7% per year. In the last decade shown (2011-2020) residential usage is projected to decline at a rate of 1.0% per year while the commercial usage decreases by an average of 0.4% per year. It is worth noting, the decline in residential and commercial usage accelerated between

2008 and 2014, with usage declining at average annual rate of 1.2% and 1,6% for residential and commercial sectors, respectively, over that period.

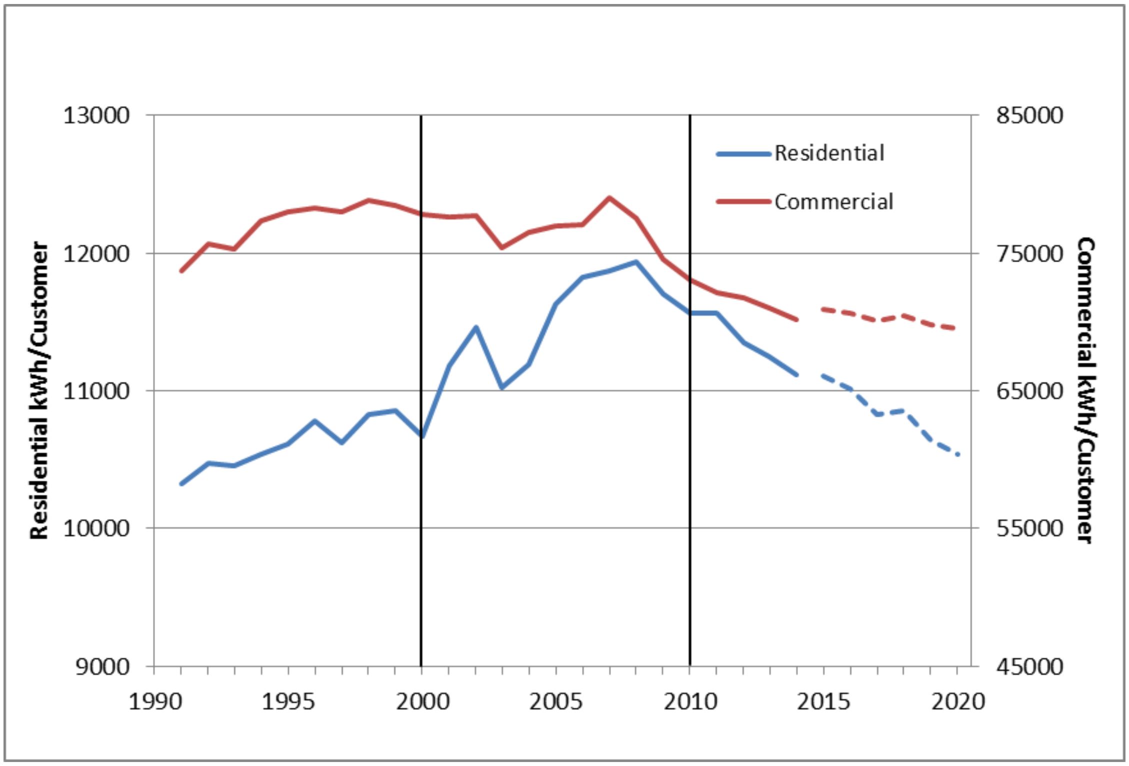

Figure 3. I&M Normalized Use per Customer (kWh)

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 the various enacted federal policy mentioned earlier.

The result of this is a base load forecast that already includes some significant reductions in usage as a result of projected energy efficiency. For example, Figure 4 below 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 13.1 in 2010 to over 13.9 by 2030. The chart shows a similar trend in projected cooling efficiencies for heat pump cooling as well as room air conditioning units as well.

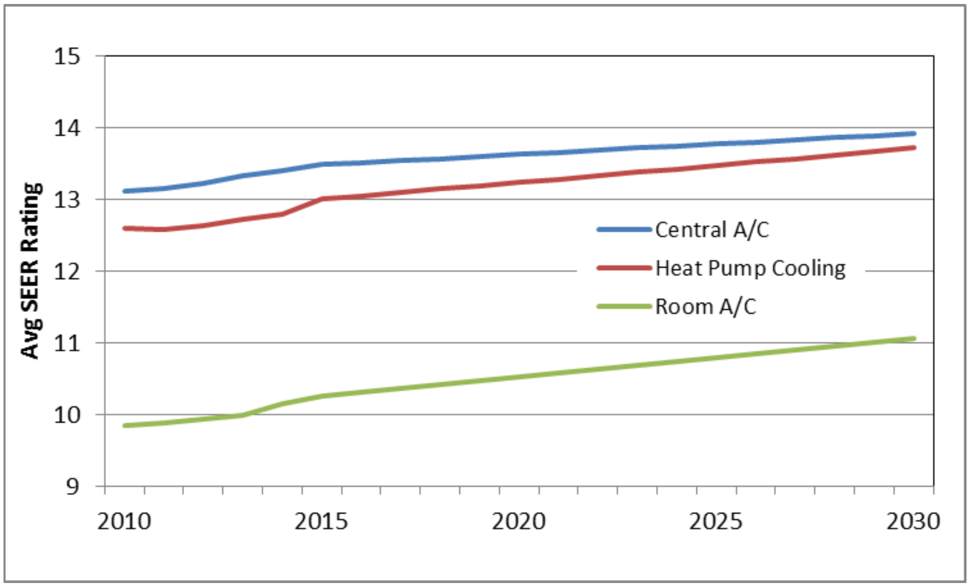

Figure 4. Projected Changes in Cooling Efficiencies, 2010-2030

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

The impact of past and ongoing customer conservation and load management activities, including DSM programs, is embedded in the historical record of electricity use and, in that sense, is intrinsically reflected in the load forecast. The load impacts of approved DSM installations are analyzed separately and subtracted from the blended sales forecast. These will typically extend for a maximum of three years. For the longer term DSM assumptions, the Company models various DSM bundles using the Plexos model to identify the optimal DSM portfolio for each year into the future based on expected future market conditions.

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 Changes in Load Forecasting Methodology

Opportunities to enhance forecasting methods are explored by I&M/AEP on a continuing basis. The forecasts reported herein reflect a limited number of changes in the methodology implemented during the last two years.

2.6.4 Interruptible Load

The Company has three customers with interruptible provisions in their contracts. These customers have interruptible contract capacity of 305MW. However, these customers are expected to have 223MW and 199MW available for interruption at the time of the winter and summer peaks, respectively. An additional 135 customers have 99MW 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 impacts are reflected by I&M in determination of PJM-required resource adequacy (i.e., I&M's projected capacity position).

2.6.5 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 year 2016 were typically taken from the short-term process. Forecast values for 2017 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 the end of 2017 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 5 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.

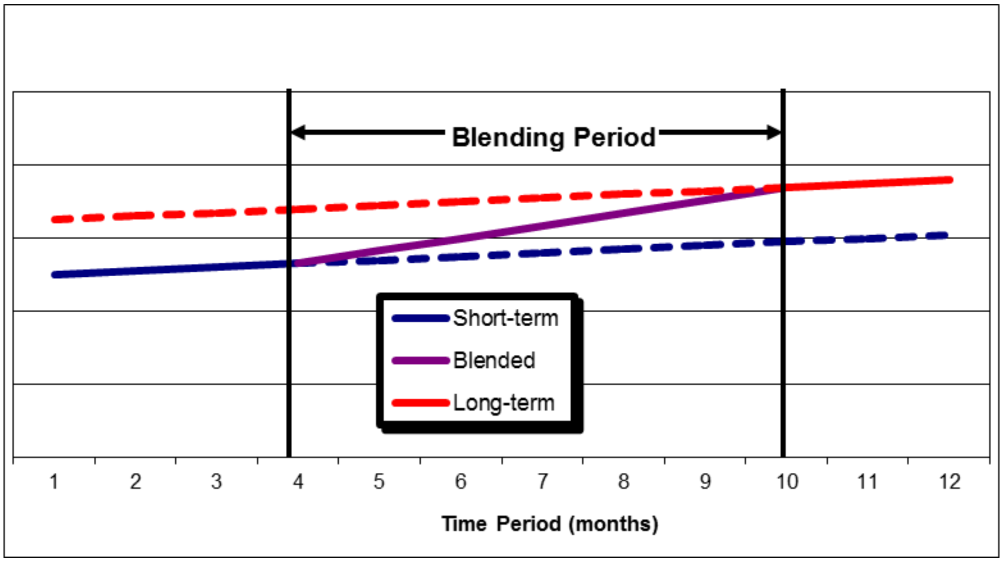

Figure 5. Load Forecast Blending Illustration

2.6.6 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 add factors may be used to reflect those large changes that are different from those from the forecast models' output.

2.6.7 Wholesale Customer Contracts

Company representatives are in continual contact with wholesale customer representatives about their contractual needs. Certain wholesale customers have provisions in their contracts that enable them to seek bids for supplying them power prior to the contract expiration. These customers need to give the Company a four year notice.

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 B, C and D of the Appendix. Due to the voluminous nature of the model outputs, only model results for energy sales in the Indiana service area and peak demand for the Company are provided.

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 two years.

2.9 Load-Related Customer Surveys

A residential customer survey was last conducted in the winter of 2013 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 is in the process of conducting a residential customer survey which will be utilized in I&M's 2018 IRP report.

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 and 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, 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 September 30, 2015, 116 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 673kW.

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 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 4.5.5.1, 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 outside of the load forecast where customer owned generation is viewed as a resource. Future IRPs may include the impacts of customer owned generation in the load forecast as its acceptance is better understood and predictable.

2.12 Load Forecast Scenarios

Even though load forecasts are created individually for each of the operating companies in the AEP System–East Zone, and aggregated to form the AEP System–East Zone total, forecast uncertainty is of primary interest at the System level, rather than the operating company level. Thus, regardless of how forecast uncertainty is characterized, the analysis begins with AEP System–East Zone load.

Among the ways to characterize forecast uncertainty are: (1) the establishment of confidence intervals with a given percentage of possible outcomes, and (2) the development of high- and low-case scenarios that demonstrate the response of forecasted load to changes in driving-force variables. I&M continues to support both approaches. However, this report uses scenarios for capacity planning sensitivity analyses.

The first step in producing high- and low-case scenarios was the estimation of an aggregated "mini-model" of AEP System–East Zone internal energy requirements. This approach was deemed more feasible than attempting to calculate high and low cases for each of the many equations used to produce the load forecasts for all operating companies. The mini-model is intended to represent the full forecasting structure employed in producing the base-case forecast for the AEP System–East Zone and, by association, for the Company. The dependent variable is total AEP System–East Zone internal energy requirements. The independent variables are real service area Gross Regional Product (GRP), the average real price of electricity to all AEP System–East Zone customer classes, and AEP System–East Zone service-area heating and cooling degree-days. Acceptance of this particular specification was based on the usual statistical tests of goodness-of-fit, on the reasonableness of the elasticity's derived from the estimation, and on a rough agreement between the model's load prediction and that produced by the disaggregated modeling approach followed in producing the base load forecast.

Once a base-case energy forecast had been produced with the mini-model, low and high values for the independent variables were determined. The values finally decided upon reflected professional judgment. The low- and high-case growth rates in real GRP for the forecast period were 0.8% and 1.9% per year, respectively, compared to 1.5% for the base case. Real electricity price high and low cases assumed average annual growth rates of 0.6% and 0.3%, respectively. Meanwhile, the base case for real electricity price assumed an average annual growth of 0.5%. Variations in weather were not considered; so the value of heating and cooling degree-days remained the same in all cases.

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. Graphical displays of the range of forecasts of internal energy requirements and summer peak demand for I&M are shown in Exhibit A-16.

For I&M, the low-case and high-case energy and peak demand forecasts for the last forecast year, 2035, represent deviations of about 10% below and 11% above, respectively, the base-case forecast.

3.0 Resource Evaluation

3.1 Current Resources

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

- Existing capacity resources—current levels and anticipated changes
- Anticipated changes in capability due to efficiency and/or environmental retrofit projects
- Changes resulting from decisions surrounding unit disposition evaluations
- Regional and sub-regional capacity and transmission constraints/limitations
- Load and peak demand
- Current DR/EE
- PJM capacity reserve margin and reliability criteria

3.2 Existing I&M Generating Resources

The underlying minimum reserve margin criterion to be utilized in the determination of I&M's capacity needs is based on the current PJM Installed Reserve Margin (IRM) of 15.7 percent.[3] The ultimate reserve margin of 8.35 percent is determined from the PJM Forecast Pool Requirement (FPR) which considers the IRM and PJM's Pool-Wide Average Equivalent Demand Forced Outage Rate ($EFOR_D$) of 6.35 percent.[4] The values for IRM, FPR, and $EFOR_D$ are updated by PJM each year.

Figure 6, below provides an overview of I&M's capacity position with respect to the Company's load obligation for the planning period. This view is considered to be the "Going-In" position, as it includes only resources which are owned, under contract, or under construction. In

[3] Per Section 2.1.1 of PJM Manual 18: PJM Capacity Market (Latest Revision: January 30, 2014). 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 published on May 19, 2015, which reflect PJM's Capacity Performance proposal.

[4] Per Section 2.1.4 of PJM Manual 18: PJM Capacity Market (Latest Revision: January 30, 2014).
$FPR = (1 + IRM) * (1 – EFOR_D)$. Reserve Margin = FPR – 1.

addition to identifying current projected peak demand requirements of its internal customers, this "going-in" position also identifies the MW capability of resources that are projected to be required to meet the minimum PJM reserve margin criterion.

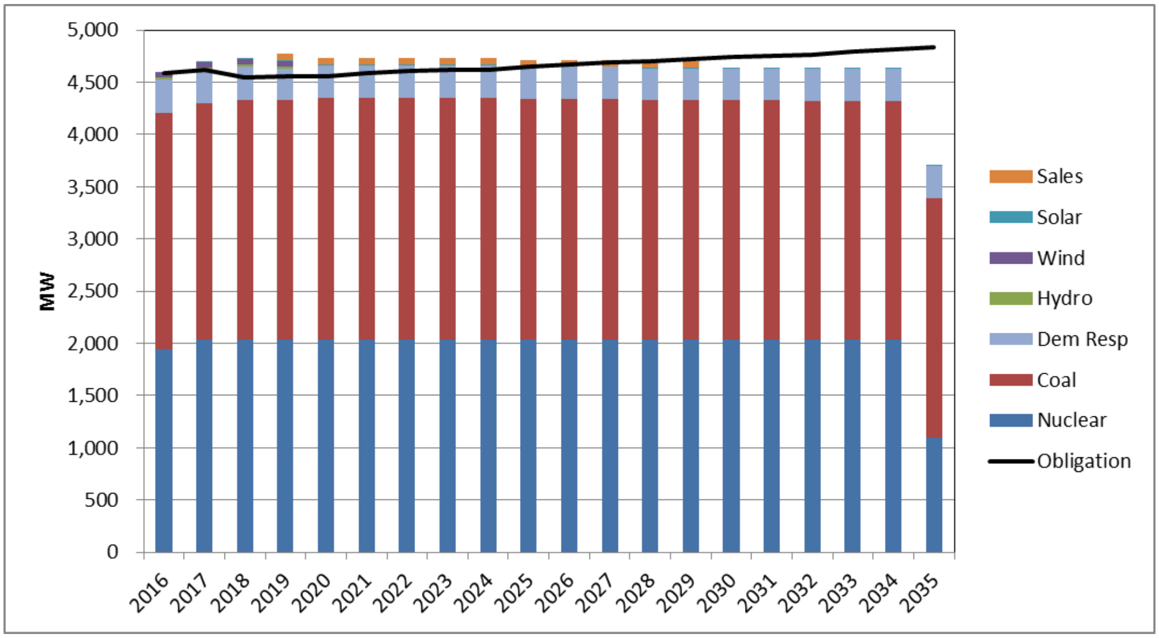

Figure 6. I&M "Going-In" PJM Capacity Position (2016-2035)

Table 2, below, displays key parameters for I&M's supply-side generation resources and Figure 7 depicts these resources along with their current age.

Table 2. Current I&M Supply-Side Resources

PLANT	UNIT	LOCATION	FUEL	IN-SERVICE DATE	NAMEPLATE RATING (MW)	PJM RATING (MW)
Berrien Springs	1-12	Berrien Springs, MI	Water	1908	7.2	6
Buchanan	1-10	Buchanan, MI	Water	1919	4.15	3.2
Clifty Creek	1	Madison, IN	Coal	1955	217	15.4 (A)
	2			1955	217	15.2 (A)
	3			1955	217	15.2 (A)
	4			1955	217	15.2 (A)
	5			1955	217	15.2 (A)
	6			1956	217	15.2 (A)
Constantine	1-4	Constantine, MI	Water	1921	1.2	0.9
Cook	1	Bridgman, MI	Nuclear	1975	1048	1006
	2			1978	1107	1053
Elkhart	1-3	Elkhart, IN	Water	1913	3.44	1.8
Fowler Ridge	1	Benton County, IN	Wind	2008	100	11.1
	2			2009	50	6.5 (C)
Headwaters	1	Randolph County, IN	Wind	2014	200	26
Kyger Creek	1	Cheshire, OH	Coal	1955	217	15 (A)
	2			1955	217	15 (A)
	3			1955	217	15 (A)
	4			1955	217	15 (A)
	5			1955	217	15 (A)
Mottville	1-4	White Pigeon, MI	Water	1923	1.68	1.6
Rockport	1	Rockport, IN	Coal	1984	1300	1118 (B)
	2			1989	1300	1105 (B)
Twin Branch	1-8	Mishawaka, IN	Water	1904	4.8	4.8
Wildcat	1	Madison County, IN	Wind	2014	100	13

(A) Represents I&M's 18% stake

(B) Represents I&M's 85% stake

(C) Represents I&M's 33% stake

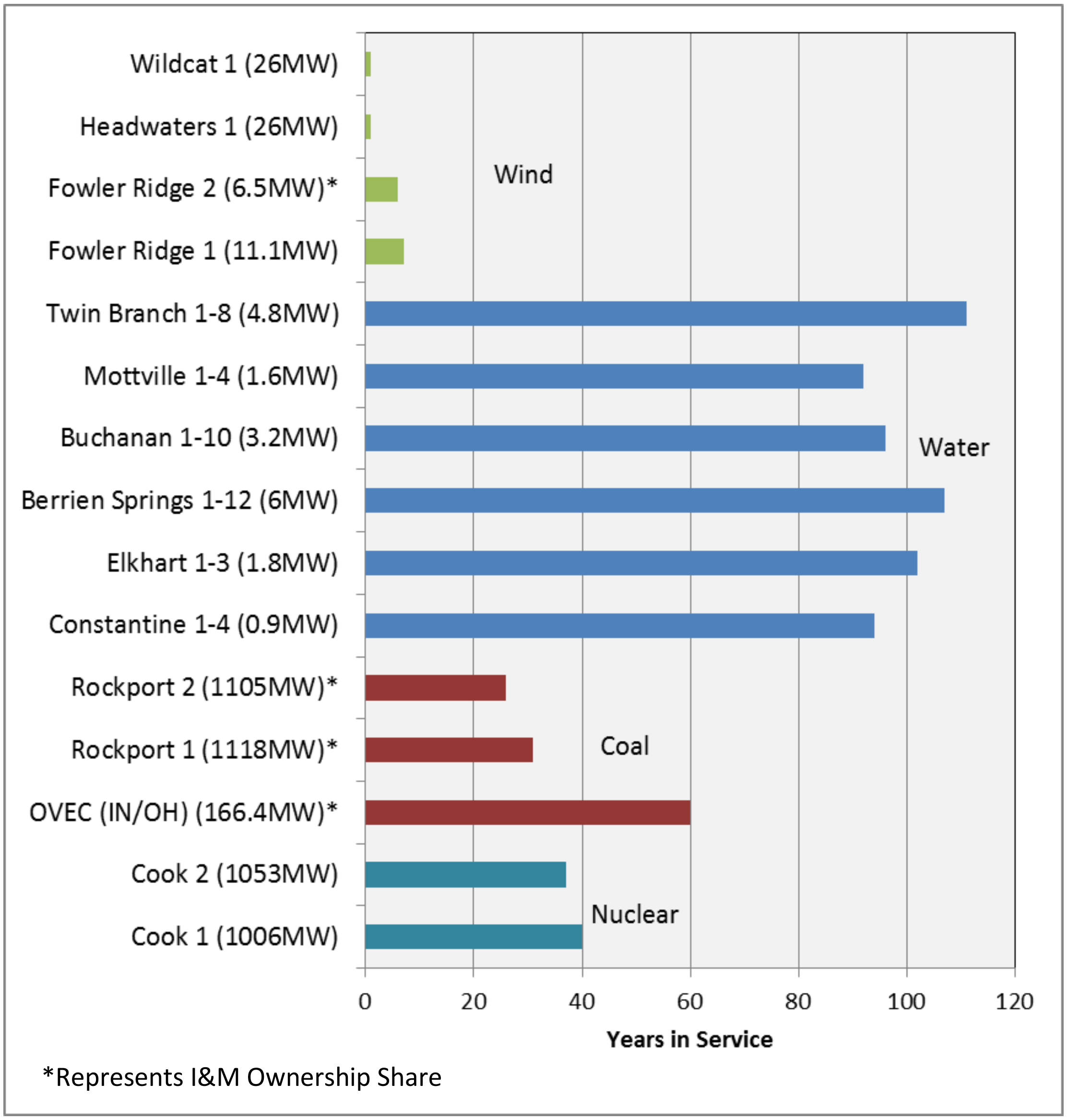

Figure 7. Current I&M Supply-Side Resources with Years in Service

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.

I&M and AEP are in the process of reviewing the full implications of the new rule. However, this IRP incorporates the following assumptions for Capacity Performance values, in order to address the Capacity Performance rule:

- Natural gas generation resources will require a firm gas supply or dual-fuel (gas/oil) capability
- Run-of-River hydro units will have no capacity value
- Solar resources will have a capacity of 38% of nameplate capacity value
- Wind resources will have no capacity value

This IRP assumes that during the 2020/2021 PJM planning year all capacity resources will need to be Capacity Performance products. It is possible that intermittent resources can be combined, or "coupled", and offered into the PJM market as Capacity Performance resources. Once the final PJM Capacity Performance tariffs become published, the Company will investigate methods in which it can maximize the utilization of its current (and future) intermittent resource portfolio within that construct. If the coupling of resources is determined to be an option, then there is a reasonable prospect that the need for incremental capacity resources set forth in this IRP could be reduced.

3.2.2 Fuel Inventory and Procurement Practices - Coal

I&M is expected 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 a continuous supply of quality coal at the lowest reasonable 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 Powder River Basin (PRB) coal from Wyoming and low-sulfur bituminous coal from eastern 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. Sources of coal are established by taking into account contractual obligations and existing sources of supply. I&M's total coal requirements are met using a portfolio of long-term arrangements and spot-market purchases. Long-term contracts support a relatively stable and consistent supply of coal, but do not offer 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 provide flexibility in scheduling with contract deliveries 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 2016 are being supplied primarily through a long-term supply agreement with Peabody COALSALES, LLC. In addition to this long-term contract, there are several other committed spot contracts that will 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 attempts to maintain in storage 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 2016 through 2035 are displayed in Exhibit J (Confidential) of the Appendix.

3.2.3 Large-Scale Solar

A large-scale solar power project is currently underway at four separate locations throughout the I&M service territory. These locations will provide a total of 14.7MW of nameplate capacity solar power when placed into service. Table 3 and Figure 8, below, depict the size, location, and expected in-service date of the four sites.

Table 3. Large-Scale Solar Sites Currently Under Construction

Facility #	Name	Location	MW(ac)	In-Service Date
1	Watervliet	Berrien County, MI	4.6	Q3 - 2016
2	Olive	St. Joseph County, IN	5.0	Q4 - 2016
3	Deer Creek	Grant County, IN	2.5	Q4 - 2015
4	Twin Branch	St. Joseph County, IN	2.6	Q3 - 2016
		Total	**14.7**	

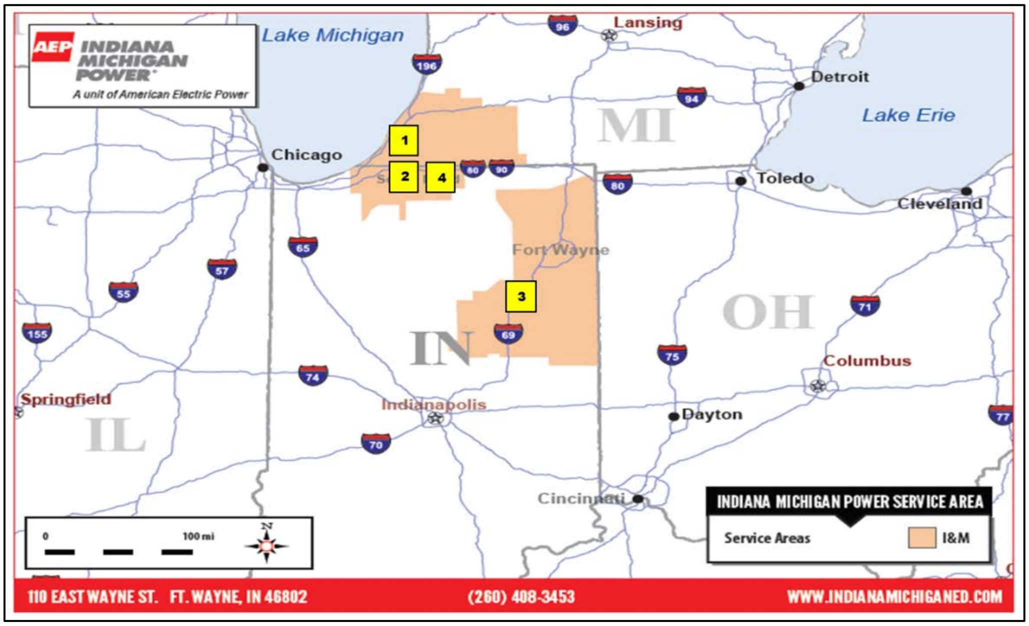

Figure 8. Location of Large-Scale Solar Sites within I&M Territory

3.3 Environmental Considerations

The following information provides background on both current and future environmental regulatory compliance plan issues with the AEP system. The Company's goal is to develop a comprehensive plan that not only allows I&M to meet the future resource needs of the Company in a reliable manner, but also to meet increasingly stringent environmental requirements in a cost effective manner.

3.3.1 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, has a groundwater monitoring well system that is sampled to monitor for any 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.

Tanners Creek, which was recently retired, utilized a wet system for all ash handling. Fly ash from all units was sluiced to a fly ash pond southwest of the plant. The pond is underlain with a 20-mil Polyvinyl Chloride (PVC) liner and is equipped with ground-water monitoring wells. As this pond's capacity was exhausted periodically it would be dewatered, excavated, and placed in the on-site landfill as its final resting place. Bottom ash from Units 1-3 was sluiced to the auxiliary ash pond. Unit 4 boiler slag was sluiced to a reclaim pond adjacent to that unit. Effluent from the fly ash, auxiliary, and reclaim ponds is routed to the main ash pond for further treatment prior to discharge to the Ohio River in accordance with the plant's NPDES permit. Closure designs for the fly ash pond, auxiliary pond, and main pond were submitted to IDEM for approval. The reclaim pond will be utilized as a storm water detention pond, and waste water treatment pond for the boiler room sumps and oil/water separator until the plant is demolished. The landfill is currently undergoing partial closure, and will be completely closed in 2016.

On December 19, 2014 the US EPA signed the final Coal Combustion Residuals (CCR) Rule which became effective on October 19, 2015. This rule will not impact the Tanners Creek Plant since the plant ceased operations prior to the effective date of the rule. However, this rule has the potential to impact the bottom ash pond at the Rockport Plant and analysis is currently underway to determine what impacts, if any, will result from the CCR Rule. Discussion of this rule is available in more detail in Section 3.3.4.3 of this section of the IRP.

Non-hazardous solid wastes generated at Rockport Plant, Tanners Creek Plant, and the Cook 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.

3.3.2 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.

Tanners Creek is typically a small quantity generator of hazardous wastes, including paints and paint-related waste, mercury waste, light bulbs, batteries, and excess/outdated chemicals. The plant recycles light bulbs, batteries and mercury waste. Process and lab chemicals that are no longer needed due to decommissioning are being properly disposed. Due to the volume of waste being removed during this process, the plant has moved into the large quantity generator status.

For the hydro facilities, hazardous waste is transferred to the Twin Branch hydro facility in Mishawaka, Indiana and stored until disposal by a licensed hazardous waste contractor. These facilities generate very little hazardous waste and typically have conditionally exempt generator status. Universal wastes such as lighting and batteries are disposed or recycled by third-party vendors from the facilities.

3.3.3 Air Emissions

There are numerous air regulations that have been promulgated or that are under development, which either will, or already do, apply to I&M's Rockport Plant. Currently, air emissions from Rockport Plant are regulated by a Title V operating permit that incorporates federal and state requirements. Other applicable requirements include those related to the Clean Air Interstate Rule (CAIR), Mercury and Air Toxics Standard (MATS) and the New Source Review (NSR) Consent Decree. The recent finalization of the CPP also applies to Rockport Plant. However, as discussed later in Section 3.3.4.7, the implementation of this rule has yet to be completed and it is not known at this time what the individual impacts will be to Rockport Plant associated with this rulemaking. Also of note are revisions to the National Ambient Air Quality Standards (NAAQS) for SO_2, Nitrogen Dioxide (NO_2), fine particulate matter, and ozone which may impact the Rockport Plant.

Potential air emissions at the Rockport Plant are reduced through the use of ESPs, low sulfur coal, low NO_x burners and Over-Fire Air (OFA), as well as a dry fly ash handling system. An ACI system is installed at Rockport Plant to reduce mercury emissions, as approved in IURC Cause No. 43636. A DSI system has also been installed to meet the Hydrochloric Acid (HCl) limit under the MATS Rule and provided for under the Modified Consent Decree, as approved in

IURC Cause No. 44331. The Modified Consent Decree is discussed further in Section 3.3.4.6. The DSI system will also allow Rockport Plant to meet future SO_2 limits identified in the Modified Consent Decree. Lastly, as approved in IURC Cause No. 44523, construction is currently underway to install Selective Catalytic Reduction (SCR) technology on Rockport Unit 1 in accordance with the Modified Consent Decree.

3.3.4 Environmental Compliance Programs

3.3.4.1 Cross-State Air Pollution Rule (CSAPR)

EPA developed the Cross-State Air Pollution Rule (CSAPR) to reduce the interstate transport of SO_2 and Nitrogen Oxides (NO_x) within 28 eastern, southern and mid-western states—including Indiana (annual SO_2, and NO_x, and ozone season NO_x) to address associated concerns related to NAAQS for ozone and particulate matter. CSAPR was finalized in 2011 as a replacement for the CAIR. Along with other requirements, the final CSAPR established state-specific annual emission "budgets" for SO_2 and annual and seasonal budgets for NO_x. Based on this budget, each emitting unit within an affected state was allocated a specified number of NO_x and SO_2 allowances for the applicable compliance period, whether annual or ozone season. Allowance trading within and between states is allowed on a regional basis.

Phase I of the CSAPR was originally intended to go into effect in January 2012. The program was delayed as a result of complicated and lengthy litigation. Although the D.C. Circuit issued a decision in 2014 vacating and remanding the rule to EPA, the U.S. Supreme Court found that the flaws identified by the D.C. Circuit did not justify vacating the rule. On remand, the D.C. Circuit held that the 2014 budgets for SO_2 in four states, and the seasonal NO_x budgets in 11 states were more stringent than necessary to eliminate any significant contribution to any downwind non-attainment area. The CSAPR is now in effect, having been published in the Federal Register on December 3, 2014 and remains in effect while EPA evaluates what changes to make to the rule. Phase 1 of the program took effect on January 1, 2015, and unless modified, the CSAPR Phase 2 emission budgets will be applicable beginning in 2017.

3.3.4.2 Mercury and Air Toxics Standard (MATS) Rule

The final MATS Rule became effective on April 16, 2012, and required compliance by April 16, 2015. This rule regulates emissions of hazardous air pollutants from coal and oil-fired electric generating units. Hazardous air pollutants regulated by this rule are: 1) mercury; 2) certain non-mercury metals such as arsenic, lead, cadmium and selenium; 3) certain acid gases, including HCl; and 4) certain organic hazardous air pollutants. The MATS Rule establishes stringent emission rate limits for mercury, filterable Particulate Matter as a surrogate for all non-mercury toxic metals, and HCl as a surrogate for all acid gases. Alternative emission limits were also established for the individual non-mercury metals and for SO_2 (alternate to HCl) for generating units that have operating Flue Gas Desulfurization (FGD) systems. The rule regulates organic hazardous air pollutants through work practice standards.

On November 25, 2014, the U.S. Supreme Court granted petitions to hear state and industry challenges against the EPA's MATS Rule to decide whether EPA unreasonably refused to consider costs in determining that it is appropriate to regulate hazardous air pollutants emitted by coal- and oil-fired electric generating units. The Supreme Court determined on June 29, 2015, that EPA must consider costs when deciding whether it is "appropriate and necessary" to regulate emissions under MATS. The decision did not vacate the MATS rule, but remanded the rule to the D.C. Circuit Court for further proceedings. MATS requirements remain effective unless otherwise ordered by the lower court.

In anticipation of requirements to reduce mercury emissions, AEP and I&M successfully tested the ability of ACI to mitigate mercury emissions at the Rockport plant in the spring of 2006. In February of 2009, after already having had incurred a significant portion of the capital investment, I&M filed for a Certificate of Public Convenience and Necessity (CPCN) for cost recovery of a permanent ACI system to be installed at the Rockport Plant. The CPCN was granted by the IURC in Cause No. 43636 in July of 2009. Rockport Plant's installed ACI system allows I&M to maintain compliance with the mercury limit under the MATS Rule. In addition to the ACI system and as provided by the Modified Consent Decree, in April of 2013 I&M filed for a CPCN for cost recovery of the installation of a DSI system at the Rockport Plant. The CPCN was granted by IURC in Cause No. 44331 in November of 2013. Rockport Plant's installed DSI system allows I&M to maintain compliance with the HCl limit under the MATS Rule. Lastly, in response to the MATS Rule, I&M retired all four units at the Tanners Creek Plant in June of 2015.

3.3.4.3 Coal Combustion Residuals (CCR) Rule

EPA signed the final CCR Rule on December 19, 2014. This rule regulates CCR, including fly ash and bottom ash, as a non-hazardous waste under Subtitle D of the Resource Conservation and Recovery Act and became effective on October 19, 2015. The CCR Rule is an extensive rule applicable to new and existing CCR landfills and CCR surface impoundments. It contains requirements, with implementation schedules, for liner design criteria for new landfills, surface impoundment structural integrity requirements, CCR unit operating criteria, groundwater monitoring and corrective actions, closure and post-closure care, and recordkeeping, notification and internet posting obligations. EPA has not included a mandatory liner retrofit requirement for existing, unlined CCR surface impoundments, however operations must cease if groundwater monitoring data indicate there has been a release from the impoundment that exceeds applicable groundwater protection standards. While the necessary site-specific analysis to determine the requirements under the final CCR Rule are currently on-going, initial estimates of anticipated plant modifications and capital expenditures are factored into this IRP.

3.3.4.4 Effluent Limitation Guidelines and Standards (ELG)

On September 30, 2015 EPA finalized a revision to the Effluent Limitation Guidelines and Standards (ELG Rule) for the Steam Electric Power Generating category. The ELG Rule requires more stringent controls on certain discharges from certain electric utility steam generating units or Electric Generating Units (EGUs) and sets technology-based limits for waste water discharges from power plants with a main focus on process water and wastewater from FGD systems, fly ash sluice water, bottom ash sluice water and landfill/pond leachate. Specifically, the ELG Rule will prohibit the discharge of fly ash and bottom ash transport water while also requiring the installation of physical/chemical/biological treatment for FGD wastewater.

I&M's Rockport Plant is well positioned to comply with the ELG Rule because it utilizes a dry fly ash handling system and also does not produce FGD wastewater. Rockport Plant does utilize a wet bottom ash handling system and initial estimates of anticipated plant modifications and capital expenditures to comply with the ELG Rule are factored into this IRP.

3.3.4.5 Clean Water Act "316(b)" Rule

A final rule under Section 316(b) of the Clean Water Act was issued by EPA on August 15, 2014, with an effective date of October 14, 2014, and affects all existing power plants withdrawing more than two million gallons of cooling water per day. The rule offers seven technology options to comply with a standard that addresses impingement of aquatic organisms on cooling water intake screens and requires site-specific studies to determine appropriate compliance measures to address entrainment of organisms in cooling water systems for those facilities withdrawing more than 125 million gallons per day. The overall goal of the rule is to decrease impacts on fish and other aquatic organisms from operation of cooling water systems. Additional requirements may be imposed as a result of consultation with other federal agencies to protect threatened and endangered species and their habitats. Facilities with existing closed cycle recirculating cooling systems may not be required to make any technology changes. This determination would be made by the applicable state environmental agency during the plants' next NPDES permit renewal cycle. If additional capital investment is required, the magnitude is expected to be relatively small compared to the investment that could be needed if the plants were not equipped with cooling towers.

Given that I&M's Rockport units are already equipped with natural draft, hyperbolic cooling towers, and these units withdraw less than 125 million gallons of water per day, the anticipated impact of the 316(b) rule is the installation of flow monitoring equipment. Compliance requirements for the Donald C. Cook Nuclear Plant ("Cook Plant") will be determined based on a site-specific study, however the implementation schedule for this rule could extend late into this decade due to the site specific nature of the permitting process.

3.3.4.6 New Source Review (NSR) Settlement

On December 10, 2007, AEP entered into a consent decree with the Department of Justice (DOJ) to resolve all allegations against AEPSC and certain of its affiliates, including I&M, related to the New Source Review (NSR) provisions of the Clean Air Act (CAA). Under the original Consent Decree I&M was bound to retrofit SCR and FGD technology on Rockport Units 1 and 2 by December 31, 2017 and December 31, 2019, respectively. Unrelated to I&M, minor changes were made to the Consent Decree in 2009 and 2010.

On February 22, 2013, AEP, along with the DOJ, EPA, and other parties, filed a proposed (3rd) Modified Consent Decree in the United States District Court for the Southern District of Ohio, Eastern Division. This Modified Consent Decree affects I&M because it provides for the installation of DSI technology on both Rockport Units by April 16, 2015, and defers the installation of higher efficiency FGD technology on the two units until December 31, 2025 and December 31, 2028. While the Modified Consent Decree provides for Rockport Plant's deferral of higher efficiency FGD technology installations on both units, 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. In addition, as part of the Modified Consent Decree Tanners Creek Unit 4 was required to either convert or retire by June 1, 2015 and I&M determined the best choice of action was to retire the unit.

The Modified Consent Decree also contains annual NO_x and SO_2 caps for the AEP operated coal units for AEP-East, of which I&M is a part. These annual caps are displayed in Table 4 and Table 5.

Table 4. Consent Decree Annual NO_x Cap for AEP-East

Calendar Year	Annual Tonnage Limitations for NO_x
2009	96,000
2010	92,500
2011	92,500
2012	85,000
2013	85,000
2014	85,000
2015	75,000
2016, and each year thereafter	72,000

Table 5. Modified Consent Decree Annual SO_2 Cap for AEP-East

Calendar Year	Annual Tonnage Limitations for SO_2
2016	145,000
2017	145,000
2018	145,000
2019-2021	113,000
2022-2025	110,000
2026-2028	102,000
2029, and each year thereafter	94,000

The Modified Consent Decree also established annual tonnage limits for SO_2 for the Rockport Plant. These annual station-wide caps are displayed in Table 6.

Table 6. 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

3.3.4.7 Carbon Dioxide (CO_2) Regulations, Including the Clean Power Plan (CPP)

On August 3, 2015, EPA finalized two rulemakings to regulate CO_2 emissions from fossil fuel-based electric generating units. EPA finalized New Source Performance Standards (NSPS) under Section 111(b) of the CAA that apply to new fossil units, as well as separate standards for modified or reconstructed existing fossil steam units. Separately, EPA finalized the CPP, which establishes CO_2 emission guidelines for existing fossil generation sources under Section 111(d) of the CAA. EPA also issued for public comment a proposed Federal Implementation Plan (FIP) to implement the CPP if states fail to submit or do not develop an approvable state plan for compliance. EPA finalized NSPS for new sources at 1,400 pounds CO_2 per megawatt-hour gross (lb/MWh-g) for new coal units based on the agency's assumption that carbon capture and storage technology can be implemented. Reconstructed coal units have a limit of 1,800 or 2,000 lb/MWh-g based on the size of the unit. The NSPS for modified coal units is site-specific based on historical operations. For new and reconstructed Natural Gas Combined Cycle (NGCC) units, the NSPS was finalized at 1,000 lb/MWh-g based on the use of efficient combustion turbine designs. No limit was proposed for modified NGCC or simple cycle units.

The Final CPP establishes separate, uniform national CO_2 emission performance rates for fossil steam units (coal-, oil-, and gas-steam based units) and for stationary combustion turbines (which EPA defines as natural gas combined cycle units). The rates were established based on EPA's application of three building blocks as the Best System of Emission Reduction (BSER) for existing fossil generating units. Block 1 assumes efficiency improvements at existing coal units. Building Block 2 assumes the increased use of NGCC units that would displace coal based generation. Lastly Building Block 3 entails the expansion of renewable energy sources that would displace generation from both coal and NGCC units. Excluded from the BSER process was consideration of nuclear energy, simple cycle gas turbines, and the previously proposed Building Block 4 related to EE measures.

From the national emission performance rates, EPA also developed equivalent state-specific emission rate goals and equivalent state-specific mass-based goals as alternatives. The final (2030) and interim (2022-2029) state emission rate and mass based goals for Indiana are listed in Table 7.

Table 7. Clean Power Plan Interim and Final Emission Goals for Indiana

	Mass-based CO_2 Emission Goals (short tons)		Rate-based CO_2 Emission Goals (lbs/net MWh)	
State	**Interim Period 2022-2029**	**Final Goal 2030**	**Interim Period 2022-2029**	**Final Goal 2030**
Indiana	85,617,065	76,113,835	1,451	1,242

EPA included interim rates in the final rule, but extended the initial compliance period start from 2020 to 2022. States that decide to develop a State Plan to implement the CPP have the option of developing either an "emissions standards approach" that would apply directly to the affected units, or a "state measures approach" that would incorporate other elements into the compliance strategy. An initial draft State Plan must be submitted to EPA by September 6, 2016. A two year extension for submitting a final State Plan is available if certain criteria are met by the state. If states do not submit an approvable plan to EPA, EPA will adopt a FIP, based on model rules that will be open for public comment when published in the Federal Register. The model rules are expected to be finalized in the summer of 2016.

I&M is currently in the process of reviewing these rulemakings and must undertake significant new analyses to understand the impacts of the Final CPP. I&M, AEP, and other stakeholders will be working in the coming months and years to better understand the requirements of the Final CPP, and to work with state agencies on the state's response to the final CPP.

3.3.5 Future Environmental Rules

As discussed earlier in Section 3.3.4, many environmental regulations have been recently finalized that apply to the electricity generating sector including revisions to several NAAQS. The CAA requires the EPA to establish and periodically review NAAQS designed to protect public health and welfare. The recently revised NAAQS include those for SO_2 (revised in 2010), NO_2 (revised in 2010), fine particulate matter (revised in 2012), and ozone (revised in 2015). These revised NAAQS have not yet been fully implemented by the states and it is anticipated that state implementation plans may need to be updated to include any SO_2 and/or NO_x emission reductions necessary to demonstrate attainment with the revised NAAQS. The scope and timing of any potential emission reduction requirements associated with these NAAQS revisions is uncertain at this time.

3.4 Current Demand-Side Programs

3.4.1 Background

Current 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 reduce consumption at the peak are (peak) DR programs, while around-the-clock measures are typically categorized as 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 "existing" EE programs that have been previously approved in Indiana and Michigan. 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 smart-grid related projects such as Electric Energy Consumption Optimization (EECO), are modeled on the same economic basis as supply-side resources.

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

The EISA requires, among other things, a phase-in of heightened lighting efficiency standards, appliance standards, and building codes. The increased standards will have a pronounced effect on energy consumption. Many of the standards already in place impact lighting. For instance, beginning in 2013 and 2014 common residential incandescent lighting options have begun their phase out as have common commercial lighting fixtures. Given that lighting options have comprised a large portion of utility-sponsored energy efficiency programs over the past decade, this pre-established transition has already been incorporated into the SAE long-term load forecast modeling previously describe in Section 2. These pre-established measures may greatly affect the market potential of utility energy efficiency programs in the near and intermediate term. Table 8, illustrates the current schedule for the implementation of new EE standards.

Table 8. Forecasted View of Relevant Improvements of Energy Efficiency Standards

Today's Efficiency or Standard Assumption
1st Standard (relative to today's standard)
2nd Standard (relative to today's standard)

End Use	Technology	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cooling	Central AC	SEER 13													
	Room AC	EER 9.8		EER 11.0											
	Evaporative Central AC	Conventional													
	Evaporative Room AC	Conventional													
Cooling/Heating	Heat Pump	SEER 13.0/HSPF 7.7			SEER 14.0/HSPF 8.0										
Space Heating	Electric Resistance	Electric Resistance													
Water Heating	Water Heater (<=55 gallons)	EF 0.90			EF 0.95										
	Water Heater (>55 gallons)	EF 0.90			Heat Pump Water Heater										
Lighting	Screw-in/Pin Lamps	Incandescent		Advanced Incandescent - tier 1 (20 lumens/watt)						Advanced Incandescent - tier 2 (45 lumens/watt)					
	Linear Fluorescent	T12	T8												
Appliances	Refrigerator/2nd Refrigerator	NAECA Standard		25% more efficient											
	Freezer	NAECA Standard		25% more efficient											
	Dishwasher	Conventional (355kWh/yr)	14% more efficient (307 kWh/yr)												
	Clothes Washer	Conventional (MEF 1.26 for top loader)			MEF 1.72 for top loader			MEF 2.0 for top loader							
	Clothes Dryer	Conventional (EF 3.01)			5% more efficient (EF 3.17)										

Source: AEG-Kentucky Power Market Potential Study Kickoff

The impact of improving electrical efficiency, including innovation and emerging and standards, on I&M's load forecast can be seen in Figure 9. Over the planning period (2016-2035) improving efficiency is forecasted to reduce retail load 8%. This impact is referred to in this report as "Non-DSM Energy Efficiency" as these energy savings are the result of EE which is not part of an I&M sponsored program.

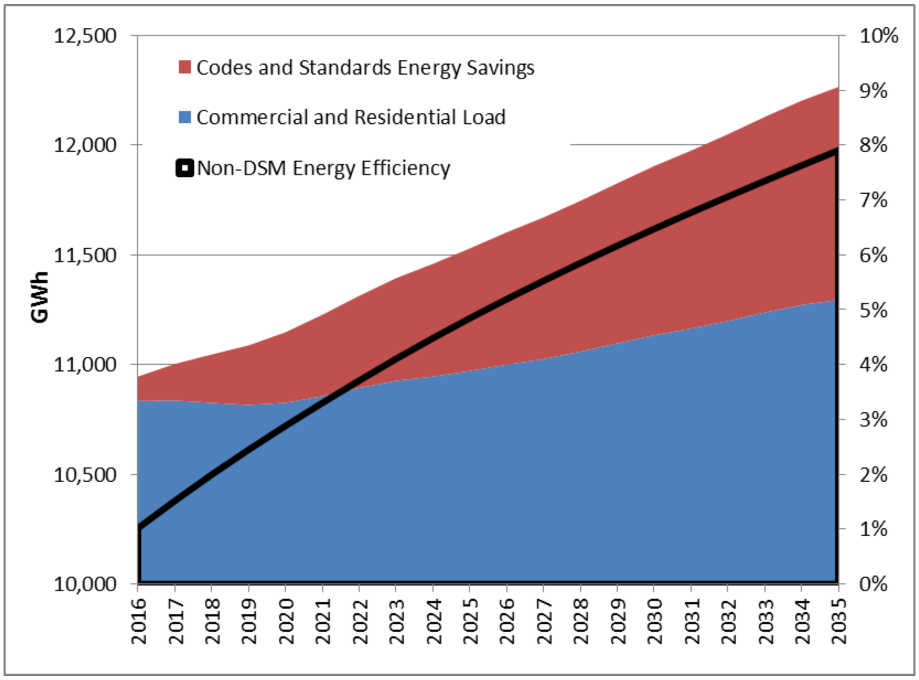

Figure 9. Impact of Non-DSM Energy Efficiency on I&M Retail Load over Planning Period (2016-2035)

I&M has implemented EE programs for 2015 which provide demand savings of 15MW. An additional 12MW of demand savings due to EE programs is expected in 2016 and 10MW in 2017. This IRP considers attainment of these levels and the subsequent continuation of the program at the same level and has embedded such levels of energy efficiency savings into I&M's load forecast

The amount of EE demand (MW) included in the load forecast varies from the amount included in the 2015 DSM Plan filed with the IURC. This variation is due to both differences in methodologies between the DSM program development process and the load forecasting process and the timing of when peak demands are predicted to occur. During the development of DSM programs peak demand savings which are assumed to occur at a given date and time are quantified. The savings for all programs are then aggregated to determine the total DSM demand savings.

During the load forecasting process, the total energy savings of the DSM programs is the basis for determining the peak demand savings but those forecast energy savings are applied to I&M system load shapes which can vary from those load shapes used to estimate DSM program demand savings. This is because other loads with their own load shapes, and timing, make up the total I&M system demand load shape. The resulting I&M system load shape is used to determine the demand savings from the programs at the time of I&M's system peak demand This value is considered to be the peak demand savings of the DSM programs in the IRP.

3.4.3 Current DR/EE Programs

For the year 2015, the Company anticipates 313MW of peak demand reduction (total Company basis); consisting of 15MW and 298MW of "passive" EE and "active" DR peak demand reductions activity, respectively.[5] I&M currently operates energy efficiency as well as load management (demand reduction) programs in both Indiana and Michigan service territories. Both states have approved rate-design programs to promote EE programs.

3.4.4 Demand Reduction

Peak demand, measured in megawatts (MW), can be thought of as the amount of power used at the time of maximum power usage. I&M's maximum (system peak) is likely to occur on the hottest summer weekday of the year, in the 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 and (industrial) machinery. At all other times during the day, and throughout the year, the use of power is less.

As peak demand grows with the economy and population, new capacity must ultimately be built. To defer the addition of new capacity resources, the amount of power consumed at the peak must be reduced. This can be addressed several ways via both "active" and "passive" measures:

[5] "Passive" demand reductions are achieved via "around-the-clock" *energy efficiency* program activity as well as voluntary price response programs; while "Active" DR is centered on focused summer peak reduction initiatives, including interruptible contracts and electric load management/direct load control programs.

- *Interruptible loads (Active DR)*. 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 (Active DR)*. 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 (Active DR)*. 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) and 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 (Passive DR)*. 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.
- *Line loss mitigation (Passive DR)*. A line loss results during the transmission and distribution of power from the generating plant to the end user. To the extent that these losses can be reduced, less energy is required from the generator.

What may be apparent is that, with the exception of EE and line loss measures, the remaining DR programs do not significantly reduce the amount of power consumed by customers. Less power may be consumed at the time of peak load, but that power will be consumed at some point during the day. For example, if rates encourage someone to avoid running their clothes dryer at four in the afternoon they will run it at some other point in the day. This is often referred to as load shifting.

3.4.5 Energy Efficiency (EE)

EE measures save money for customers billed on a per kilowatt-hour usage basis. The trade-off is the reduced utility bill for any up-front investment in a building/appliance/equipment modification, upgrade, or new technology. If the consumer feels that the new technology is a viable substitute and will pay him back in the form of reduced bills over an acceptable period, he 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. According to a March 2007 DOE study such benefits include:

- Economics: Reduced energy intensity provides competitive advantage and frees economic resources for investment in non-energy goods and services
- Environment: Saving energy reduces air pollution, the degradation of natural resources, risks to public health and global climate change.
- Infrastructure: Lower demand lessens constraints and congestion on the electric transmission and distribution systems
- Security: Energy Efficiency can lessen vulnerability to events that cut off energy supplies

However, as summarized in Table 9, market barriers to EE exist for the potential participant.

Table 9. Energy Efficiency (EE) Market Barriers

High First Costs	Energy-efficient equipment and services are often considered "high-end" products and can be more costly than standard products, even if they save consumers money in the long run.
High Information or Search Costs	It can take valuable time to research and locate energy efficient products or services.
Consumer Education	Consumers may not be aware of energy efficiency options or may not consider lifetime energy savings when comparing products.
Performance Uncertainties	Evaluating the claims and verifying the value of benefits to be paid in the future can be difficult.
Transaction Costs	Additional effort may be needed to contract for energy efficiency services or products.
Access to Financing	Lending industry has difficulty in factoring in future economic savings as available capital when evaluating credit-worthiness.
Split Incentives	The person investing in the energy efficiency measure may be different from those benefiting from the investment (e.g., rental property)
Product/Service unavailability	Energy-efficient products may not be available or stocked at the same levels as standard products.
Externalities	The environmental and other societal costs of operating less efficient products are not accounted for in product pricing or in future savings

Source: Eto, Goldman, and Nadel (1998): Eto, Prahl, and Schlegel (1996); and Golove and Eto (1996)

To overcome many of the participant barriers noted above, a portfolio of 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 a major determinant in the pace of market transformation and 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 2018 that are incremental to approved or mandated programs.

3.4.5.1 Energy Conservation

Often used interchangeably with efficiency, conservation results from foregoing the benefit of electricity either to save money or simply to reduce the impact of generating electricity. Higher rates for electricity typically result in lower consumption. Inclining block rates, or rates that increase with usage, are rates that encourage conservation.

3.4.6 Smart Grid Technologies and Opportunities

3.4.6.1 Distributed Generation (DG)

Distributed Generation (DG) typically refers to small scale customer-sited generation downstream of the customer meter. Common examples are residential and small commercial solar applications, small wind installations and CHP. Currently, these sources represent a small component of demand-side resources; even with available Federal tax credits. Currently, the vast majority of DG within I&M is residential solar.

Both I&M retail jurisdictions do have "net metering" tariffs in place which allow for the sale of power generated by customers to be purchased by the utility at the customers' (retail) rate. Most power generated in this manner is consumed "on-site" and the net power available to be fed back into the grid for system use is negligible.

The economics of DG, particularly solar, continue to improve. Figure 10, below, charts the fairly rapid decline of expected installed solar costs in I&M's service territory, based on a combination of AEP market intelligence and the Bloomberg New Energy Finance's (BNEF) Installed Cost of Solar forecast. These are costs shown *without* accounting for the 30% Federal Investment Tax Credit (ITC) (reduced to a 10% credit in 2016).

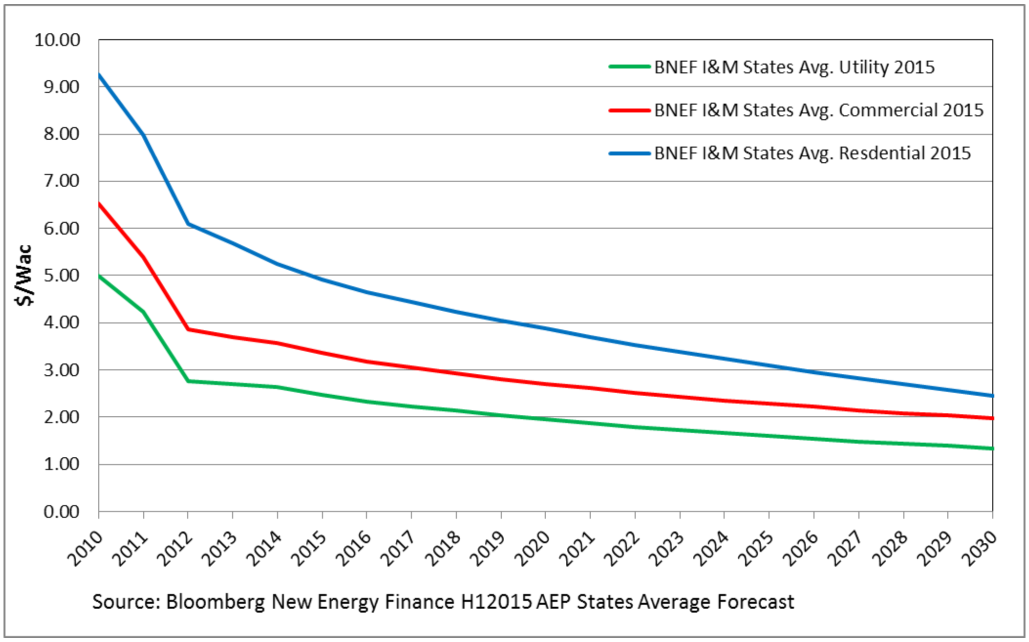

Figure 10. Recent and Forecasted Solar Installed Costs for I&M Territory (Excl. Fed & State Incentives)

Figure 11, below demonstrates the historical installed rooftop solar capacity for I&M by jurisdiction and the projected rooftop solar capacity additions that are included in the Preferred Portfolio.

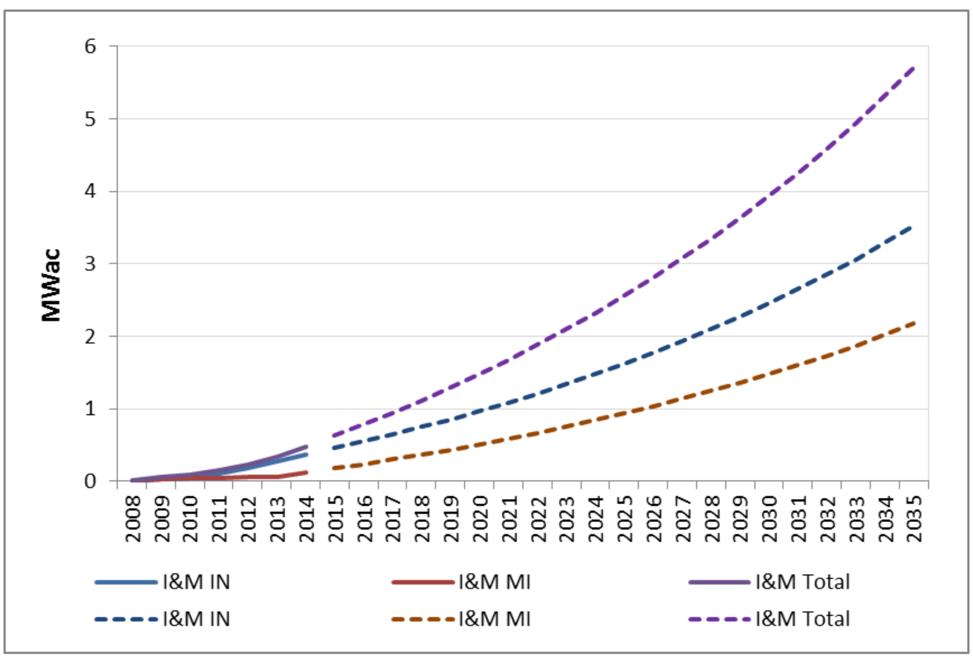

Figure 11. Cumulative Distributed Generation (Rooftop Solar) Additions/Projections for I&M

The assumed growth rate for rooftop solar is estimated at 5% per year based on both the declining cost for rooftop solar as well as the historical additions by I&M state jurisdiction.

3.4.6.2 Electric Energy Consumption Optimization (EECO)

An emerging technology known as 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 12, 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 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. Early results from limited rollouts in AEP affiliate operating companies indicate a range of 0.7% to 1.2% of energy demand reduction for a 1% voltage reduction is possible.

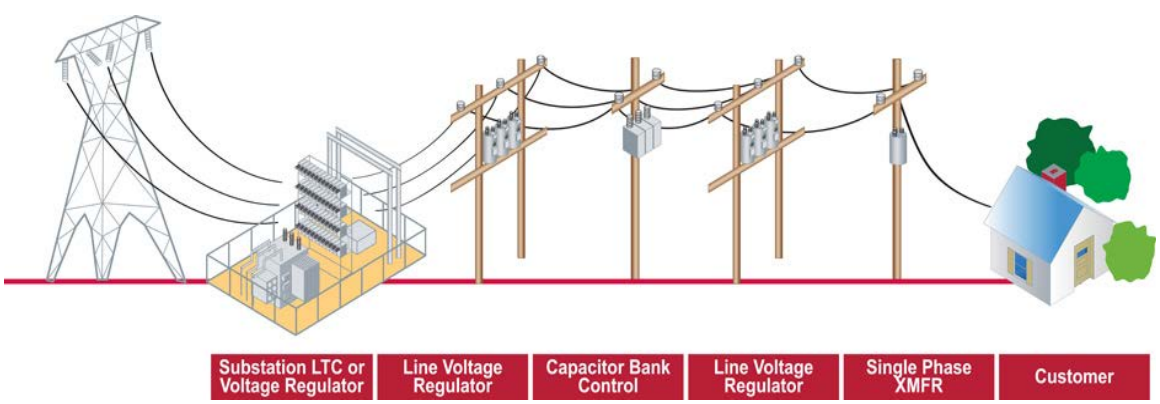

Figure 12. Electric Energy Consumption Optimization (EECO) Schematic

While there is no embedded EECO load reduction impacts implicit in the base load forecast case, EECO has been modeled as a unique EE resource. The results of which are discussed in Section 4.

3.5 AEP-PJM Transmission

3.5.1 General Description

The AEP East Transmission System (eastern zone) consists of the transmission facilities of the six eastern AEP operating companies (APCo, OPCo, I&M, KPCo, Wheeling Power Company and Kingsport Power Company). This transmission system spanning portions of seven states is planned and operated on an integrated basis and is comprised of over 14,000 miles of circuitry operating at or above 138kV. The system includes over 2,100 miles of 765kV overlaying over 3,400 miles of 345kV and allows AEP to economically and reliably deliver electric power to over 25,000MW of customer demand (AEP demand plus the demand served by municipals and cooperatives connected to the transmission system of the AEP System East Zone).

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* (RFC) geographic area. On October 1, 2004, AEP's eastern zone joined the PJM RTO and now participates in the PJM markets.

As a result of the AEP Eastern Transmission System's geographical location and expanse as well as its numerous interconnections, the Eastern Transmission System can be influenced by both internal and external factors. 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 North American Electric Reliability Corporation (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. Several transmission enhancements within the I&M region of the AEP Eastern Transmission System are currently in the process of engineering and/or construction. Most notably are the improvements around Fort Wayne, Indiana, such as the Sorenson station upgrades currently in progress. This project brings the existing 765kV line between the Dumont and Marysville stations into Sorenson station. The project also introduces the first application of the new Breakthrough Overhead Line Design (BOLD) transmission line technology developed by AEP and will be constructed between the Sorenson and Robison Park stations. AEP will continue to expand the AEP System East Zone transmission system, as appropriate, to provide reliable service to meet the load growth of I&M's customers. AEP's Eastern Transmission System assets are aging. Figure 13 demonstrates the development of AEP's Eastern Transmission Bulk Electric System (BES). In order to maintain reliability, significant investments will have to be made in the rehabilitation of existing assets over the next decade.

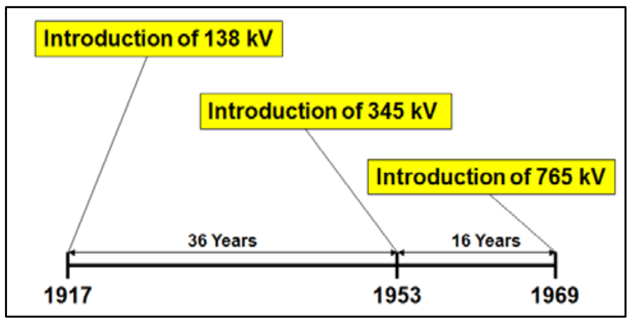

Figure 13. Timeline of AEP's Eastern Transmission Bulk Electric System Development

Over the years, AEP, and now PJM, entered into numerous study agreements to assess the impact of the connection of potential merchant generation to the Eastern Transmission System. Currently, there is more than 25,000MW of AEP generation and approximately 6,250MW of additional merchant generation connected to the Eastern Transmission System. There has been a significant increase in interconnection requests for connection to the AEP transmission system due to renewable energy development efforts, largely wind power facilities proposed in Indiana and Western Ohio. AEP, in conjunction with PJM, has interconnection agreements in the AEP service territory with several merchant plant developers for additional generation to be connected to the Eastern Transmission System over the next several years. The amount of this planned generation that will actually come to fruition is unknown at this time. 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 changes in local voltage profiles resulting from operation of the PJM and Midcontinent Independent System Operator (MISO) markets.

The retirement of 13,000MW of generation throughout the PJM region has already begun and will continue as necessary into the coming years. The I&M region of the AEP Eastern Transmission System has already seen the retirement of the Tanners Creek units (495MW) in Southern Indiana. Not only is this a loss of capacity, but also the support of dynamic voltage regulation to the system. Projects in I&M, like the previously mentioned Sorenson improvements, are underway to address the need for stronger sources to generation-deficient areas like Fort Wayne, Indiana. The current and future projects that are developed will ensure that the AEP Eastern Transmission System will continue to operate reliably into the future as changes, such as generation retirements, continue. In addition, within the Eastern Transmission System, there are two areas in particular that could require significant transmission enhancements to allow the reliable integration of large generation facilities:

- Southern Indiana—there are limited transmission facilities in southern Indiana relative to the AEP generation resources, and generation resources of others in the area. Significant generation additions to AEP's transmission facilities (or connection to neighbor's facilities) will likely require significant transmission enhancements, including Extra-High Voltage (EHV) line construction, to address thermal and stability constraints. The Joint Venture Pioneer Project would address many of these concerns. The Pioneer Transmission, LLC is a joint venture formed by Duke Energy and AEP in 2008 to build and operate approximately 240 miles of EHV 765kV transmission lines and related facilities in Indiana.

- Megawatt Valley—the Gavin/Amos/Mountaineer/Flatlick area currently has stability limitations during multiple transmission outages. Multiple overlapping transmission outages will require the reduction of generation levels in this area to ensure continued reliable transmission operation, although such conditions are expected to occur infrequently. Significant generation resource additions in the Gavin/Amos/Mountaineer/Flatlick area will also influence these stability constraints, requiring transmission enhancements–possibly including the construction of EHV lines and/or the addition of multiple large transformers– to more fully integrate the transmission facilities in this generation-rich area. Thermal constraints will also need to be addressed.

Furthermore, even in areas where the transmission system is robust, care must be taken in siting large new generating plants in order to avoid local transmission loading problems and excessive fault duty levels.

The transmission line circuit miles in Indiana include approximately 600 miles of 765kV, 1,380 miles of 345kV, and 1,430 miles of 138kV lines, as well as over 400 miles of 69kV and approximately 500 miles of 34.5kV lines. Exhibit I (Confidential) displays a map of the entire AEP System-East Zone transmission grid, including I&M.

3.5.2 Transmission Planning Process

AEP and PJM coordinate the planning of the transmission facilities in the AEP System-East 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 (OA). By way of the RTEP, PJM will ensure that transmission expansion is developed for the entire RTO footprint via a single regional planning process, assuring 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 AEP with a regional view and formalized open stakeholder input.

AEP's transmission planning criteria is consistent with NERC and RFC reliability standards. The AEP planning criteria are filed with FERC annually as part of AEP's FERC Form 715 (Exhibit H of the Appendix) and these planning criteria are posted on the AEP website.[6] 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 the anticipated deficiency.

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 OA between PJM and the MISO provides for joint transmission planning.

3.5.3 System-Wide Reliability Measure

At the present time, there is no single measure of system-wide reliability that covers the entire system (transmission, distribution, and generation). However, in practice, 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 uses 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

[6] http://www.aep.com/about/codeofconduct/OASIS/TransmissionStudies/GuideLines/2015_AEP_PJM_FERC_715_Final_Part_4.pdf

problems under adverse system conditions. Whenever a potential problem is identified, AEP seeks solutions to avoid the occurrence of the problem. Solutions may include operating procedures or capital transmission 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.

In addition, PJM performs a Load Deliverability assessment on an annual basis using a 90/10[7] 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 currently has 17 active queue positions within Indiana totaling approximately 4,794MW (nameplate), including projects that are either in various stages of study (14 projects), under construction (1 projects), or in-service (2 project). Of these active queue positions, 14 are wind generation requests. 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

[7] 90% probability that the peak actual load will be lower than the forecasted peak load and 10% probability that the acutal peak load will be higher than the forecasted peak load.

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

3.5.7 Transmission Project Descriptions

A detailed list and discussion of the AEP transmission projects that have recently been completed or presently underway in Indiana can be found in Section 3.5.9 (Indiana Transmission Projects) of this report. In addition, several other projects beyond the I&M area have also been completed or are underway across the AEP System-East 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 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 within the State of Indiana. 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 eastern AEP System reliability criteria for transmission planning, as well as the assessment practice used, is provided in AEP's FERC Form 715 Annual Transmission Planning and Evaluation Report, 2015 filing. That filing also provides transmission maps, and pertinent information on power flow studies and an evaluation and continued adequacy assessment of AEP's Eastern Transmission System. Pertinent excerpts from this report to meet the 170 IAC requirements are contained in Exhibit H of the Appendix.

As the Transmission Planner for AEP and AEP subsidiaries in the east, PJM performs all required studies to assess the robustness of the BES. 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. Any request for current cases, models, or results should 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) Multi-regional Modeling Working Group (MMWG) power flow library, the PJM base cases, or the neighboring company itself. In general, sufficient detail is retained to adequately assess all events, outages and changes in generation dispatch, which are contemplated in any given study.

3.5.9 Indiana Transmission Projects

A brief summary of the transmission projects in I&M's Indiana service territory for the 2013-2017 timeframe is provided below. Project information includes the project name, a brief description of the project scope, projected in-service date, and projected cash flows[8] by year for each project.

- Mishawaka Area Improvements: Several 138kV and 34.5kV line overloads in the Elkhart area were identified by both PJM and AEP due to an outage of East Elkhart 345/138kV transformer. Construction of a new 15 mile Twin Branch – East Elkhart 138kV circuit using the vacant side of the existing tower line and developing a new 138/34.5kV station, Capital Avenue, to interconnect the existing 34.5kV network will help alleviate these conditions. As part of the proposal, the distribution load will also be consolidated at the new 138/34.5kV Capital Avenue station and the existing Currant Road station will be retired. This project is a joint project with the I&M Transmission Company. The cash flows listed below are only for the I&M portion of the project and exclude the I&M Transmission Company portion.
    - 2013: $5.5 million
    - 2014: $0.5 million

- South Side and South Bend Upgrades: PJM identified overloads on the Twin Branch – South Bend 138kV line and the Jackson Road – South Side 138kV line. To alleviate these overloads, I&M will replace terminal equipment at South Side and South Bend stations and perform a sag study on the Twin Branch – South Bend 138kV line and the Jackson Road – South Side 138kV line to improve the summer emergency rating of both lines. The cash flows listed below are only for the I&M portion of the project.
    - 2013: $0.1 million
    - 2014: $0.6 million

- Bosserman Upgrades (New LaPorte Junction): Analysis indicated a potential thermal overload on the 69kV around AEP's LaPorte Junction station for the loss of Olive - Laporte Junction - Michigan City 138kV line. To alleviate the thermal overloads, construction of a new 138kV breaker-and-a-half Bosserman station was proposed.

[8] Cash flows are approximated.

The existing Laporte Junction station will continue to operate, but will be supplied from the new Bosserman station. The cash flows listed below are only for the I&M portion of the project.2014: $0.1 million

- 2015: $0.7 million

- Northern Fort Wayne Improvements: PJM and AEP identified overloads on the Auburn – Dekalb 138kV circuit for loss of two 138kV sources into the Northern Fort Wayne area. AEP has also demonstrated that several contingencies in the area can cause severe thermal overload and voltage conditions and a possible blackout in Northern Fort Wayne jeopardizing the bulk electric system (BES) in Indiana. To alleviate these concerns, the following major improvements are proposed: Rebuilding the Auburn-Robison Park 138kV single-circuit line as a double-circuit line, replacing the Auburn 138/69kV transformer with a larger unit, rebuilding the Robison Park 138kV station yard, establishing the Clipper 69/12kV station, retiring various sub-transmission facilities, and construction of a new Dunton Lake 138kV switching station. This project is a joint project with I&M Transmission Company. The cash flows listed below are only for the I&M portion of the project and exclude the I&M Transmission Company portion.
    - 2012: $0.1 million
    - 2013: $2.2 million
    - 2014: $6.1 million
    - 2015: $5.5 million
    - 2016: $0.2 million

- Southern Indiana Improvements: AEP is noticing a change in the flow patterns in the southern Indiana area. The 765kV outlets were not originally designed for the flow pattern of heavy west to east flows. The root cause of this change in flow patter is the addition of over 25GW of generation around southern Indiana, southern Illinois and western Kentucky since 1989. Also, since the transmission facilities sit at the seams of Midwest ISO and PJM, high voltages are experience on the 345kV network. The proposed improvements including the change in shunt reactor size at Rockport and transposition of 765kV lines will help mitigate these constraints. This project is a joint project with I&M Transmission Company. The cash flows listed below are only for the I&M portion of the project and exclude the I&M Transmission Company portion.

  - 2013: $10.1 million
  - 2014: $7.9 million
  - 2015: $0.2 million

- <u>Breed Rebuild (Sullivan 345kV)</u>: The Breed 345kV switching station, located in southwest Indiana, provides connections to several neighboring utilities in Illinois and southern Indiana, connects to the Sullivan 765/345kV station, and provides support to the transmission network that extends to the northern Indiana wind corridor. Breed houses some of the oldest 345kV transmission equipment in the AEP system. Much of the equipment in the station is obsolete, and repair parts are either special order or unavailable on the market. Rather than replacing the station equipment at the present location, it is recommended to rebuild the Breed station adjacent to the nearby Sullivan 765kV Station. Doing so will eliminate current equipment failure concerns, potential environmental risks, and will reduce compliance exposure. This project is a joint project with I&M Transmission Company. The cash flows listed below are only for the I&M portion of the project and exclude the I&M Transmission Company portion.
  - 2013: $0.9 million
  - 2014: $1.4 million
  - 2015: $3.8 million
  - 2016: $0.5 million

- <u>Dequine Bus Reactor Additions</u>: Studies indicated that the Dequine 345kV station could experience high voltage under 2016 light load contingency conditions. To alleviate this concern, this project proposes the addition of two 150 MVAR bus reactors at Dequine station, one on each bus, in addition to two 345kV circuit breakers on Westwood #1 and #2 circuits for needed reliability improvement.

- 2015: $1.4 million
- 2016: $0.2 million

- Meadow Lake – Reynolds Line Rebuild: An overload was identified by PJM on the Meadow Lake to Reynolds 345kV line during their RTEP analysis of generation deliverability and N-1 contingency analysis. To alleviate the thermal overload, rebuild of the existing nine mile double circuit 345kV line from Meadow Lake to Reynolds is proposed under this project. Certain station upgrades at Meadow Lake, Reynolds, and Olive stations will also be performed under this project.
  - 2015: $0.2 million
  - 2016: $0.9 million
  - 2017: $0.6 million

- Ball State University Load Increase: Ball State University is increasing its load to accommodate a geothermal project on campus and conversion to 12kV service. To serve this load, I&M is rebuilding the Tillotson 34.5kV station and replacing the underground cables that feed Ball State's Christy Woods station. This will allow for future load growth and replaces an old, deteriorating station. This project is a joint project with I&M Transmission Company. The cash flows listed below are only for the I&M portion of the project and exclude the I&M Transmission Company portion.
  - 2015: $0.2 million
  - 2016: $0.4 million
  - 2017: $3.4 million
  - 2018: $0.2 million

- Greater Fort Wayne Area Improvements: PJM identified low voltage violations at numerous buses in the greater Fort Wayne area in the 2015 case study. I&M is proposing to expand the existing Sorenson station and establish a new 765kV source to the area to mitigate the future voltage concerns. The new source at Sorenson requires a new 345kV path to be constructed between Sorenson and Robison Park stations. This new 345kV line will be completed by rebuilding an existing 138kV line between the two stations as a double-circuit tower line. One side of the new line will be 345kV and the other side will remain 138kV to serve existing stations along the path. This project is a joint project with I&M Transmission Company. The cash flows listed below are only for the I&M portion of the project and exclude the I&M Transmission Company portion.

- 2013: $1.2 million
- 2014: $6.2 million
- 2015: $15.3 million
- 2016: $8.2 million
- 2017: $0.1 million

- Allen Station Expansion: PJM identified overloads on several 138kV lines in the 2016 study case. I&M's proposed solution includes a station expansion and transformer addition to the existing Allen station. Several miles of 138kV line will be constructed to help alleviate local overloads identified by PJM. This project is a joint project with I&M Transmission Company, Ohio Power, and Ohio Transmission Company. The cash flows listed below are only for the I&M portion of the project and exclude the other portions.
  - 2013: $0.4 million
  - 2014: $2.4 million
  - 2015: $1.8 million
  - 2016: $6.4 million
  - 2017: $3.4 million

- Randolph Area Improvements: PJM identified low voltage violations in the Randolph, Indiana area in the 2015 study case. I&M's is proposing to expand Selma Parker station and install a 138/69kV transformer to introduce a new source to the area to alleviate the low voltage violations. This project is a joint project with I&M Transmission Company. The cash flows listed below are only for the I&M portion of the project and exclude the I&M Transmission Company portion.

  - 2013: $0.1 million
  - 2014: $2.5 million
  - 2015: $2.4 million

- Daleville Area Improvements: PJM identified overloads on the Desoto – Madison 138kV circuit. To fix the overload, I&M will replace terminal equipment at Daleville station and perform a sag study on the line.
  - 2013: $0.1 million
  - 2014: $0.03 million
  - 2015: $0.1 million

- City of Fort Wayne Improvements: To better serve the customers in the downtown Fort Wayne area, I&M is proposing to introduce a second 138kV source to Spy Run station by rebuilding an existing 34.5kV line as a double circuit tower line. One side will be operated at 138kV while the other will remain at 34.5kV. The 34.5kV network will also be upgraded as needed to accommodate the new 138kV source and rearrangement of the distribution network. This project is a joint project with I&M Transmission Company. The cash flows listed below are only for the I&M portion of the project and exclude the I&M Transmission Company portion.
  - 2013: $0.6 million
  - 2014: $2.6 million
  - 2015: $1.4 million
  - 2016: $6.7 million
  - 2017: $4.8 million
  - 2018: $1.0 million

- Southern Fort Wayne Improvements: I&M is proposing to convert an aging 34.5kV line to 69kV. The stations currently served from the 34.5kV line will also be converted to 69kV. This will eliminate future voltage concerns and allow for the retirement of aging infrastructure. This project is a joint project with I&M Transmission Company. The cash flows listed below are only for the I&M portion of the project and exclude the I&M Transmission Company portion.

  - 2013: $0.01 million
  - 2014: $0.6 million
  - 2015: $0.8 million
  - 2016: $3.3 million
  - 2017: $1.2 million

- <u>Therma Tru Customer Project:</u> The transmission customer *Therma Tru* made the decision to replace their 7.5MVA 69/12kV transformer with two 10MVA 69/12kV transformers. I&M's scope for this project was limited to installing new 69kV metering and making adjustments to the 69kV feed into the customer owned station.
  - 2013: $0.2 million

- <u>Milan Station Improvements:</u> The transmission customer Michelin made the decision to increase their load by approximately 10MVA and requested a third 138kV feed for a new transformer at the customer-owned Goodrich station. To meet this request, I&M's scope for this project involved a rebuild of Milan station, which serves Michelin, as well as constructing the new 138kV feed to the customer station. This project is a joint project with I&M Transmission Company. The cash flows listed below are only for the I&M portion of the project and exclude the I&M Transmission Company portion.
  - 2013: $0.7 million
  - 2014: $0.2 million
- <u>Hadley – Kroemer Line Project:</u> Sections of existing conductor on the Hadley – Kroemer 69kV circuit were found to be more limiting than previously documented, causing a PJM baseline project to be established that would rebuild the affected

sections of the line.
  - o 2014: $1.1 million
  - o 2015: $1.2 million

- Herbert Monroe 138kV Line Purchase: The Paulding Putnam Co-op previously owned a small portion of 138kV line serving a customer station, the Herbert Monroe station. As part of this project, Paulding Putnam sold the line and associated rights-of-way to AEP.
  - o 2015: $0.3 million

- Melita Area Improvements: The central Fort Wayne area is in need of increased distribution capacity and reliability improvements. This project establishes a new Melita 69/12kV station with four distribution transformers, which will replace the existing Webster 34.5kV station. The new Melita station will be served from three 69kV circuits, two of which will be new construction, while the third circuit is an existing 34.5kV line that will be converted to 69kV. This project is a joint project with I&M Transmission Company. The cash flows listed below are only for the I&M portion of the project and exclude the I&M Transmission Company portion.
  - o 2015: $0.2 million
  - o 2016: $3.8 million
  - o 2017: $2 million

- Aviation Station Improvements: The existing I&M customer BAE Systems is moving to a new location and expanding operations at the new facility. The new location requires establishing a new Aviation 138/12kV distribution station to reliably serve the customer into the future. This new distribution station will also serve local I&M distribution customers as well. The station will be served by two 138kV circuits. This project is a joint project with I&M Transmission Company. The cash flows listed below are only for the I&M portion of the project and exclude the I&M Transmission Company portion.

  - 2016: $0.3 million
  - 2017: $0.4 million

- Jay Area Improvements: This is a PJM baseline project to alleviate violations identified during a 2016 RTEP generator deliverability study. The project will install two new 138kV circuit breakers at the Randolph station, replace two 138kV circuit breakers and required equipment at the Jay station, as well as a new 138kV circuit breaker at the Hodgin station. Transmission line work is also required for the Jay – College Corner 138kV line entering Randolph station. This project is a joint project with I&M Transmission Company. The cash flows listed below are only for the I&M portion of the project and exclude the I&M Transmission Company portion.
  - 2013: $0.5 million
  - 2015: $2.0 million
  - 2016: $2.5 million

- Grant Station Improvements: This project calls for relay upgrades at both the Grant and Greentown stations due to past mis-operations and to solve for a PJM-identified overload of the Grant – Greentown 138kV line, which is limited by the existing relays.
  - 2015: $0.9 million
  - 2016: $0.7 million

- Losantville 345kV IPP Project: This project was initiated by the PJM generation interconnection queue U2-090. The wind developer Horizon has installed 200MW of wind generation that connects to the AEP Desoto – Tanners Creek 345kV Ckt#2 at a newly established Losantville Station. Since this is an IPP project, the developer is responsible for all interconnection costs, therefore the costs listed below are considered reimbursable. This project is a joint project with I&M Transmission Company. The cash flows listed below are only for the I&M portion of the project and exclude the I&M Transmission Company portion.

- 2015: $2.0 million

- Tanners Creek Improvements: This project focuses on replacing multiple 345kV circuit breakers as well as relay upgrades for the 345kV and 138kV yards, which meet current AEP standards. The project was initiated after three 345kV circuit breakers were identified by PJM to be an over duty concern. This project is a joint project with I&M Transmission Company. The cash flows listed below are only for the I&M portion of the project and exclude the I&M Transmission Company portion.
  - 2015: $0.1 million
  - 2017: $0.6 million

- Eugene – Sidney 345kV Line Rebuild: Approximately two miles of the Eugene – Sidney 345kV line is in need of rehabilitation. This project will rebuild the identified two-mile section of line and upgrade any remote end equipment/relaying. This project is a joint project with I&M Transmission Company. The cash flows listed below are only for the I&M portion of the project and exclude the I&M Transmission Company portion.
  - 2014: $0.1 million
  - 2015: $0.7 million

- Indiana SCADA Additions: In an effort to improve/expand monitoring and supervisory control at I&M transmission stations a program was started in 2012. The intent of this program is to scope, engineer, and implement full Supervisory Control and Data Acquisition (SCADA) installations/ upgrades at stations where monitoring and control is most needed. The overall program includes stations in both Indiana and Michigan. The cash flows listed below are only for those stations in Indiana.
  - 2013: $1.2 million
  - 2014: $2.4 million
  - 2017: $1.5 million

- 23rd Street Reconfiguration: In order to improve reliability and address equipment age concerns at the 23rd Street station, this project was established to reconfigure the 34.5kV lines coming into the station. The project includes retiring aging circuit breakers while optimizing those breakers that will not be replaced.
    - 2016: $0.3 million
    - 2017: $3.5 million

- 23rd Street Area Improvements: This project originates from a compliance coordination effort with the I&M customer Westinghouse to remove a customer-owned battery which controlled a BES circuit breaker at the Westinghouse station. The project removes the aging 138kV circuit breaker at Westinghouse and will install a new 138kV circuit breaker at the nearby 23rd Street Station. This eliminates the concern associated with the customer-owned battery and also addresses the rehabilitation of an older 138kV breaker. The project will also rearrange the 138kV connections in and out of the Westinghouse and 23rd Street stations. This project is a joint project with I&M Transmission Company. The cash flows listed below are only for the I&M portion of the project and exclude the I&M Transmission Company portion.
    - 2014: $0.1 million
    - 2015: $0.8 million
    - 2016: $3.4 million

- Alexandria Area Improvements: This project will address PJM-identified 138kV voltage violations at Mullin, Strawton, and South Elwood stations for various 138kV contingencies in the area along with significant 34.5kV network load. The project will establish a new 138kV line between Strawton and Jones Creek stations to alleviate the voltage concerns. To address the heavy loading on the 34.5kV network, Alexandria Station will be rebuilt (now called Aladdin Station) with two new 138/12kV distribution banks to transfer a portionof the area load to the 138kV system. In addition, a 138/34.5kV transformer will be added at Strawton providing another source for the area. Overall, the project will eliminate the need for approximately 20 miles of existing 34.5kV lines that are in poor condition. This project is a joint project with I&M Transmission Company. The cash flows listed below are only for the I&M portion of the project and exclude the I&M Transmission Company portion.

- 2015: $0.2 million
- 2016: $3.2 million
- 2017: $5 million

- Marathon Service Customer Project: I&M customer Marathon Pipeline LLC has requested 69kV electric service delivery for a new 5,000HP pumping station having a 4.2 MVA Capacity to be located near Hartford City, Indiana. The service plan will involve installing a new three-way motorized switch (to be called Fulkerson Switch) along the Hartford City – Armstrong Cork 69kV line, and construct approximately three miles of new 69kV line to the customer location. This project is a joint project with I&M Transmission Company. The cash flows listed below are only for the I&M portion of the project and exclude the I&M Transmission Company portion.
  - 2016: $0.2 million

- East Elkhart EHV Circuit Breaker Additions: As part of an overall EHV circuit breaker addition program the East Elkhart station will have a three breaker ring bus configuration installed on the 345kV circuit breaker. The existing configuration involves a tap with motor operated switches. The new ring bus configuration will provide a significant increase to the reliability of the station. This project is a joint project with I&M Transmission Company. The cash flows listed below are only for the I&M portion of the project and exclude the I&M Transmission Company portion.
  - 2014: $0.1 million
  - 2015: $0.3 million
  - 2016: $0.3 million

- East Elkhart 138kV Circuit Breakers: This project was initiated to replace five 138kV circuit breakers and switches in need of rehabilitation at the East Elkhart Station. This project is a joint project with I&M Transmission Company. The cash flows listed below are only for the I&M portion of the project and exclude the I&M Transmission Company portion.
    - 2015: $0.2 million

- Colfax – Drewry's 34.5kV Project: PJM has identified, in its 2020 RTEP, an overload of a 34.5kV line in the South Bend, Indiana area of AEP's service territory. To solve for this overload, I&M has planned to establish a new 34.5kV line between Colfax and Drewry's Stations. This project will also rebuild Drewry's to address the existing station age and the needs of the future infrastructure. This project is a joint project with I&M Transmission Company. The cash flows listed below are only for the I&M portion of the project and exclude the I&M Transmission Company portion.
    - 2017: $0.5 million

- Dragoon – Kline 34.5kV Partial Rebuild: PJM has identified, in its 2020 RTEP, an overload for sections of the Dragoon – Kline 34.5kV line in the South Bend, Indiana area of I&M's service territory. To solve for the overload, I&M has planned to rebuild the line sections Dragoon – Dodge Tap and Kline – Virgil Street. This project is a joint project with I&M Transmission Company. The cash flows listed below are only for the I&M portion of the project and exclude the I&M Transmission Company portion.
    - 2017: $0.2 million

- Olive Station Distribution Project: This project is both customer and distribution capacity-driven. A new customer load of 8MVA will need to be served from the station. Additionally, the distribution bank serving residential customers is expected to reach its useful capacity. The plan for this project is to install a new 138/12kV 20MVA bank. To accomplish this, transmission upgrades at the station will be required for reliability, which includes installing one 138kV line circuit breaker and two 138kV transformer circuit breakers. This project is a joint project with I&M Transmission Company. The cash flows listed below are only for the I&M portion of the project and exclude the I&M Transmission Company portion.

- 2015: $0.5 million
- 2016: $2.8 million

- Oliver Plow Customer Project: The project is driven by new customer load and future distribution capacity needs in South Bend, Indiana. This project focuses on constructing a new 138/12kV station (Oliver Plow), which will consist of a 25MVA transformer and 12kV feeders to serve the new 10MVA General Electric/Notre Dame customer facility as well as transfer some of the load currently served by the Studebaker Station. The new station will be tapped in and out from the Studebaker – Kankakee 138kV line and have two 138kV circuit breakers. This project is a joint project with I&M Transmission Company. The cash flows listed below are only for the I&M portion of the project and exclude the I&M Transmission Company portion.
  - 2015: $0.3 million
  - 2016: $0.1 million

- Dumont Station Rehab Project: This project includes the rehabilitation and replacement of equipment at the Dumont Station. A large portion of the work will be for installation of replacement 765kV reactors and removal of the existing reactors. This project is a joint project with I&M Transmission Company. The cash flows listed below are only for the I&M portion of the project and exclude the I&M Transmission Company portion.
  - 2014: $0.2 million
  - 2015: $0.6 million
  - 2016: $2.4 million
  - 2017: $0.6 million

- Elderberry 345kV IPP Project: This project was initiated by the PJM generation interconnection queue X2-052. X2-052 is a 675MW natural gas power plant requesting interconnection to I&M's Dumont – Olive 345kV line. Since this is an IPP project, the developer is responsible for all interconnection costs, therefore the costs listed below are considered reimbursable. This project is a joint project with I&M Transmission Company. The cash flows listed below are only for the I&M portion of the project and exclude the I&M Transmission Company portion.
  - 2016: $0.2 million
  - 2017: $1.0 million

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 expansion plan that balances "least-cost" objectives with planning flexibility, asset mix considerations, adaptability to risk, conformance with applicable 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. Resources selected through the modeling process are not locational specific; therefore, specific interconnection evaluations are not conducted as part of this analysis. Locational consideration is addressed as part of the PJM RTEP process.

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

In general, assumptions and plans are continually reviewed and modified as new information becomes available to ensure that market structures and governances, technical parameters, regulatory constructs, capacity supply, energy adequacy and operational reliability, and environmental mandate requirements are routinely reassessed to ensure optimal capacity resource planning.

Further impacting 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 best or optimal plan is the one with the absolute least cost over the planning horizon evaluated. Other factors–some more difficult to monetize than others–were considered in the determination of the plan. To challenge the robustness of the ultimate Preferred Portfolio, sensitivity analyses were performed to address these factors.

4.2 Methodology

The IRP process aims to address the long-term "gap" between resource needs and current resources. Given the various assets and resources that can satisfy this expected long-term gap, a tool is needed to sort through the myriad of potential combinations and return an optimum solution–or portfolio–subject to constraints. *Plexos*® is the primary modeling application, used by I&M and AEP for identifying and ranking portfolios that address the gap between needs and current available resources.[9] Given the cost and performance parameters around sets of potentially-available supply- and demand-side proxy resources and a scenario of economic conditions that include long-term fuel prices, capacity costs, energy costs, emission-based pricing proxies including CO_2, as well as projections of energy usage and peak demand, *Plexos*® will return the optimal suite of proxy resources (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 Fundamental Modeling Input Parameters

The AEP Fundamental Analysis group derives long-term power (energy) price forecasts from a proprietary model known as AURORA^{xmp}. Having similarities to *Plexos*®, AURORA^{xmp} is a long-term fundamental production cost-based energy and capacity price forecasting tool developed by EPIS, Inc., that is driven by comprehensive, user-defined commodity input parameters. For example, nearer-term unit-specific fuel delivery and emission allowance price forecasts, based upon actual transactions, which are established by AEP Fundamental Analysis and AEP Fuel, Emissions and Logistics, are input into AURORA^{xmp}. Estimates of longer-term natural gas and coal pricing are provided by AEP Fundamental Analysis in conjunction with input received from consultants, industry groups, trade press, governmental agencies and others. Similarly, capital costs and performance parameters for various new-build generating options, by duty-type are vetted through AEP Engineering Services and incorporated into the tool. Other information specific to the thousands of generating units being modeled is researched from Velocity Suite, an on-line information database maintained by Ventyx, an ABB Company. This includes data such as unit capacity, heat rates, retirement dates and emission controls status.

[9] *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.

Finally, the model maintains and determines region-specific resource adequacy based on regional load estimates provided by AEP Economic Forecasting, as well as current regional reserve margin criterion. AEP uses AURORA^{xmp} to model long-term (market) energy and capacity prices for the entire U.S. eastern interconnect as well as Electric Reliability Council of Texas (ERCOT). The projection of a CO_2 pricing proxy is based on assumptions developed in conjunction with the AEP Strategic Policy Analysis organization. Figure 14 shows the Fundamentals process flow for solution of the long-term commodity forecast. The input assumptions are initially used to generate the output report. The output is used as feedback to change the base input assumptions. This iterative process is repeated until the output is congruent with the input assumptions (*e.g.*, level of natural gas consumption is suitable for the established price and all emission constraints are met).

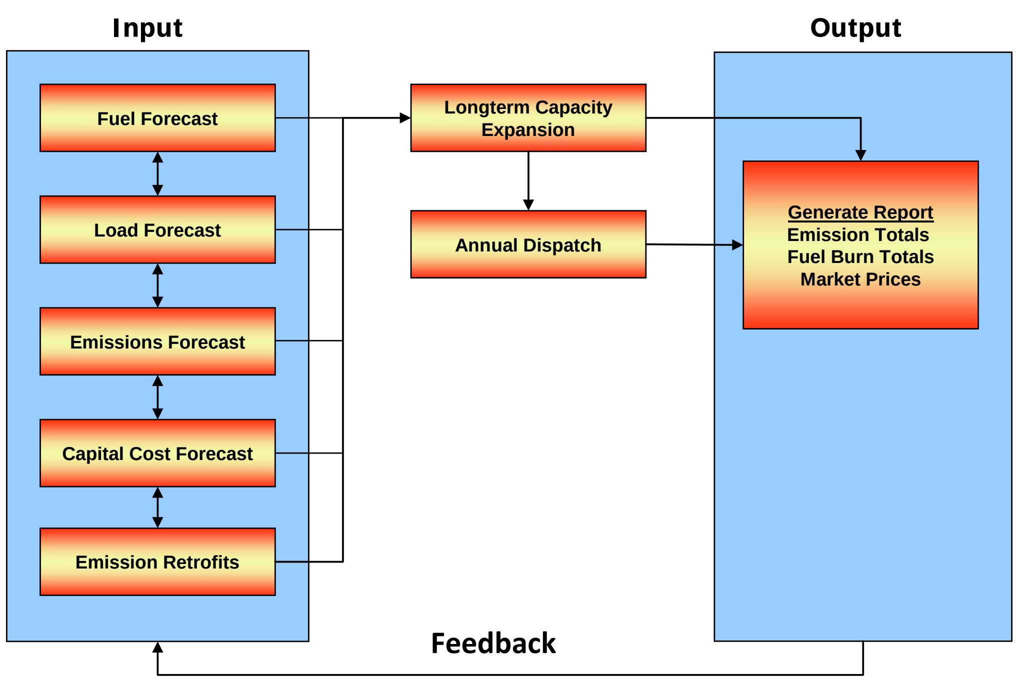

Figure 14. Long-term Power Price Forecast Process Flow

4.3.1 Commodity Pricing Scenarios

Five commodity pricing scenarios were developed by AEP Fundamental Analysis for I&M to enable *Plexos*® to construct resource plans under various long-term pricing conditions. In this report, the five distinct long-term commodity pricing scenarios that were developed for *Plexos*® are: a Base scenario view, a plausible Low Band view, a plausible High Band view; a High

Carbon view; and a No Carbon view. The scenarios are described below with the results shown in Figure 15 through Figure 20.

When comparing the following pricing scenarios with others throughout the industry it should be noted that AEP's commodity pricing forecasts account for the impacts of future events, such as proposed environmental regulations. This approach differs from other popular references, such as the EIA's Annual Energy Outlook[10].

4.3.1.1 Base Scenario

This scenario recognizes the following major assumptions:

- MATS Rule effective beginning in 2015;
- Initially lower natural gas price due to the emergence of shale gas plays; and
- CO_2 emission pricing proxy begins in 2022 and was assumed to be at $15 per metric ton, growing with inflation.

Each of the pricing forecasts includes a CO_2 impact as a result of the implementation of any prospective CO_2 reduction regulation. The Base, High Band and Low Band scenarios all reflect the fundamental view that such a CO_2 pricing proxy could be modeled as a $15/tonne dispatch cost penalty, or "tax", beginning in 2022 because it results in reduction of CO_2 emissions when combined with recent EPA regulations and standards such as MATS, more-stringent Corporate Average Fuel Economy (CAFE) standards and others. Given that any plan to reduce GHG emissions must be accompanied by a thorough assessment of the impact on the electric grid, allow adequate time for implementation, respect the authority of states and other federal agencies, and preserve a balanced, diverse mix of fuels for electricity generation, 2022 was considered to be the earliest reasonable projection as to when any such CO_2 reduction regulation could become effective when these pricing scenarios were established.

The specific effects of the MATS Rule are modeled in the development of the long-term commodity forecast by retiring the smaller, older solid-fuel (i.e., coal and lignite) units which

[10] From the Energy Information Administration's Annual Energy Outlook 2015 Preface: "The AEO2015 projections are based generally on federal, state, and local laws and regulations in effect as of the end of October 2014. The potential impacts of pending or proposed legislation, regulations, and standards (and sections of existing legislation that require implementing regulations or funds that have not been appropriated) are not reflected in the projections (for example, the proposed Clean Power Plan[3])". Available at http://www.eia.gov/forecasts/aeo/preface.cfm

would not be economic to retrofit with emission control equipment. The retirement time frame modeled is 2015 through 2017. Those remaining solid-fuel generating units will have some combination of controls necessary to comply with the EPA's rules. Incremental regional capacity and reserve requirements will largely be addressed with new natural gas plants. One effect of the expected retirements on the emission control retrofit scenario is an over-compliance of the previous CSAPR emission limits. This will drive the emission allowance prices for SO_2 and NO_x to zero by 2018 or 2019.

4.3.1.2 Low Band Scenario

This scenario is best viewed as a plausible lower natural gas/solid-fuel/energy price profile compared to the Base scenario. In the near term, Low Band natural gas prices largely track the Base but, in the longer term, natural gas prices represent an even more significant infusion of shale gas. From a statistical perspective, this long-term pricing scenario is approximately one (negative) standard deviation (-1.0σ) from the Base scenario and illustrates the effects of coal-to-gas substitution at plausibly lower gas prices. Like the Base scenario, proxied CO_2 mitigation/pricing is assumed to start in 2022 at a $15 per metric ton (real dollars).

4.3.1.3 High Band Scenario

Alternatively, this High Band scenario offers a plausible, higher natural gas/solid-fuel/energy price profile compared to the Base scenario. High Band natural gas prices reflect certain impediments to shale gas developments including stalled technological advances (drilling and completion techniques) and as yet unseen environmental costs. The pace of environmental regulation implementation is in line with the Base scenario and Low Band. Analogous to the Low Band scenario, this High Band view, from a statistical perspective, is approximately, one (positive) standard deviation ($+1.0\sigma$) from the Base. Also, like the Base and Low Band scenarios, CO_2 pricing is assumed to begin in 2022 at the same $15 per metric ton (tonne) pricing proxy.

4.3.1.4 No Carbon Scenario

This scenario does not consider the prospects of a carbon tax. While also including the necessary correlative fuel price adjustments, it serves as a baseline to understand the impact on unit dispatch and, with that, the attendant impact on energy prices associated with the Base and High Carbon scenarios.

4.3.1.5 High Carbon Scenario

Built upon the assumption of a $25 per tonne (66% higher than the Base scenario) CO_2 mitigation pricing proxy beginning in 2022, the High Carbon scenario includes correlative price adjustments to natural gas and solid-fuel due to changes in consumption that such heightened CO_2 pricing levels would create. This results in some additional retirements of coal-fired generating units around the implementation period. Natural gas and, to a lesser degree, renewable generation are typically built as replacement capacity.

The following set of figures illustrates the range of such long-term pricing projections, on a nominal dollar basis, by major commodity through the year 2030.

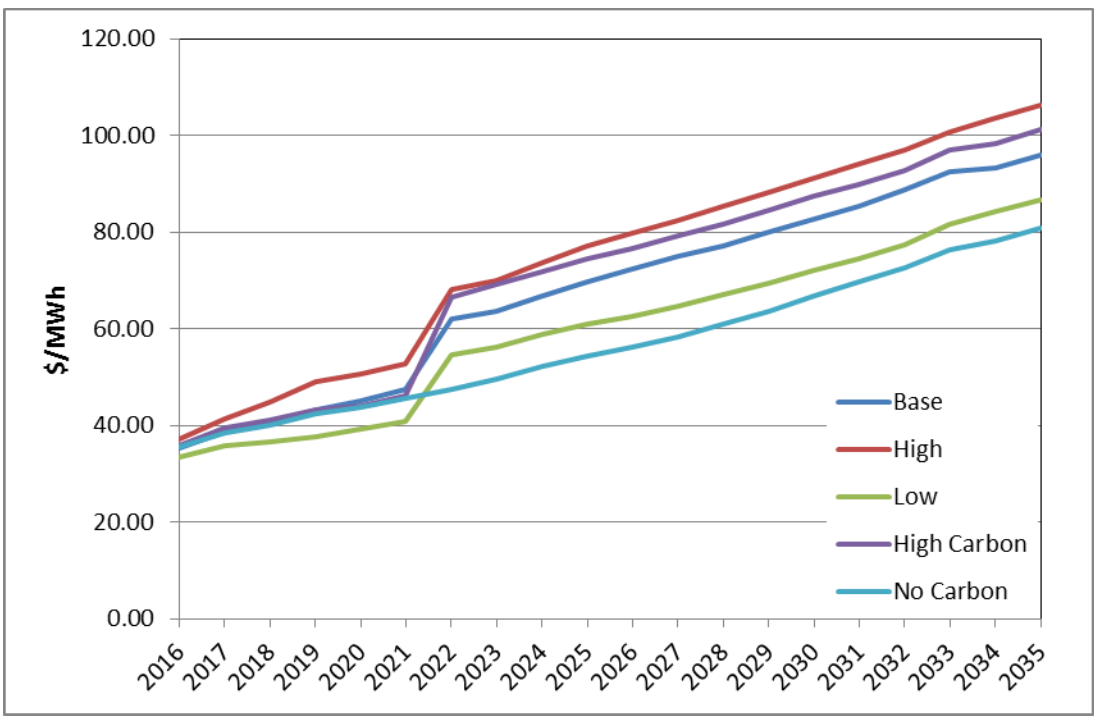

Figure 15. PJM On-Peak Energy Prices (Nominal $/MWh)

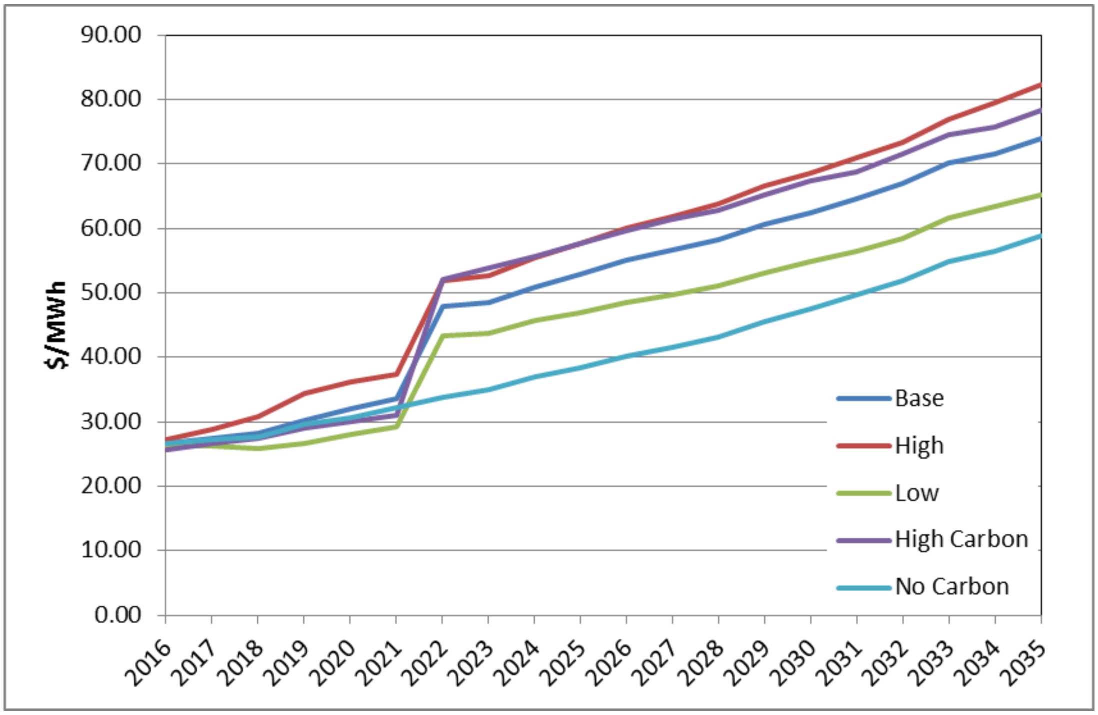

Figure 16. PJM Off-Peak Energy Prices (Nominal $/MWh)

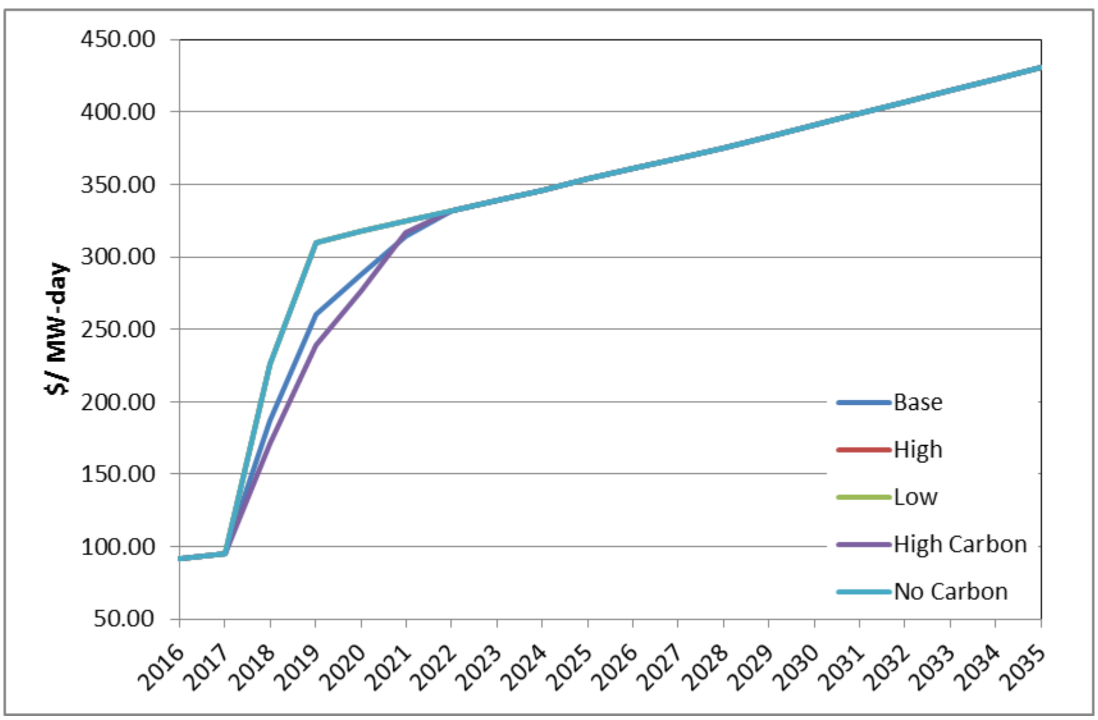

Figure 17. PJM Capacity Prices (Nominal $/MW-day)

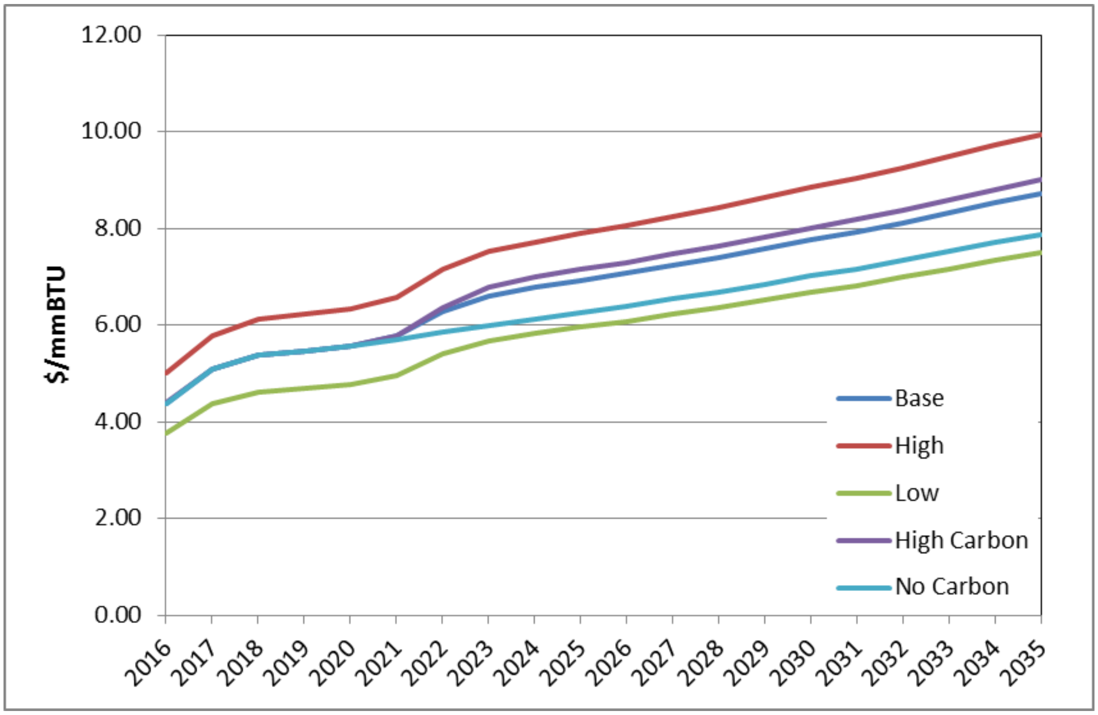

Figure 18. TCO (Delivered) Natural Gas Prices (Nominal $/mmBTU)

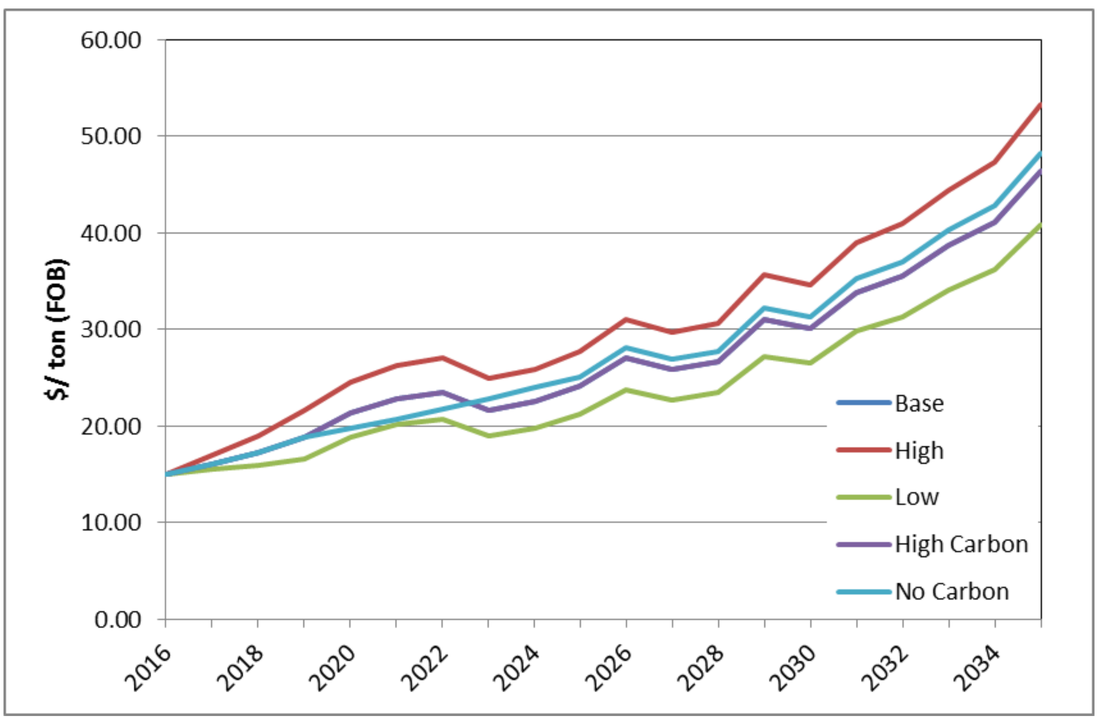

Figure 19. PRB 8,800 BTU/lb. Coal Prices (Nominal $/ton, FOB)

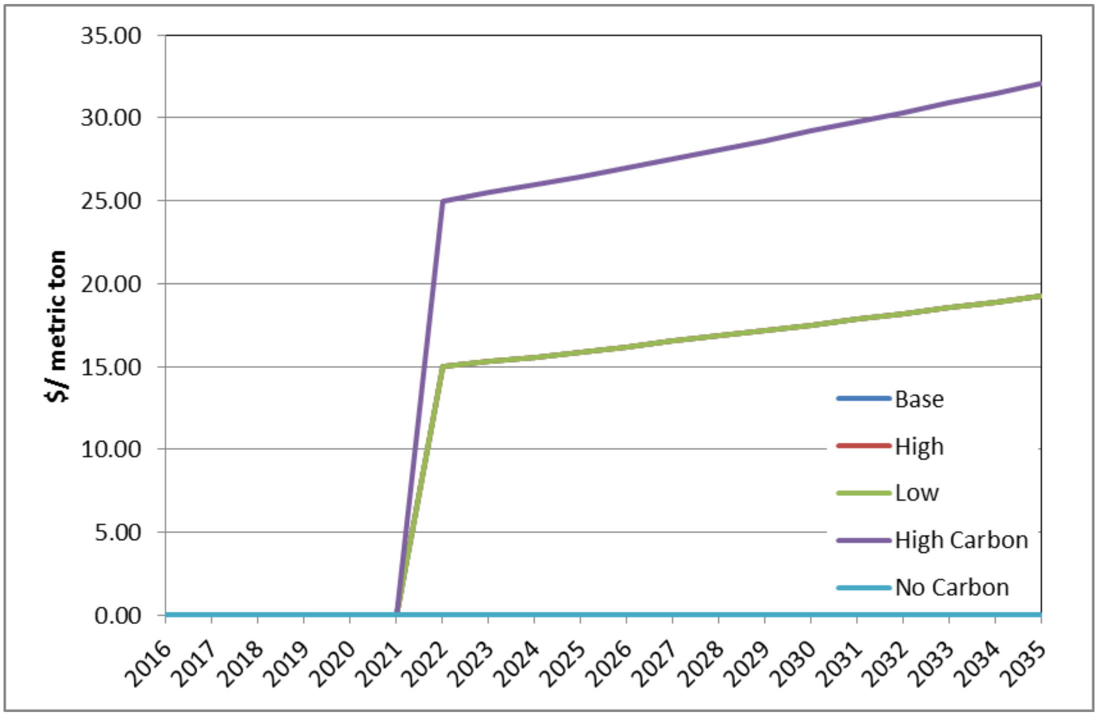

Figure 20. CO_2 Prices (Nominal $/metric ton)

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

4.4.1 Overview

The process for evaluating DSM impacts for I&M is practically divided into two spheres; "existing programs" and "future activity." Existing programs are those that are known or are reasonably well-defined, follow a pre-existing process for screening and determining ultimate regulatory approval. The impacts of such existing I&M DSM programs are propagated throughout the long-term I&M load forecast and were discussed in Section 3.4.3. Future program impacts which are, naturally, less-defined, are developed with a dynamic modeling process using more generic cost and performance parameter data.

For I&M, the potential future DSM activity was developed and ultimately modeled based on the Electric Power Research Institute's (EPRI) "2014 U.S. Energy Efficiency Potential Through 2035" report. This comprehensive report served as the basic underpinning for the establishment of potential EE "bundles", developed for residential and commercial customers that were then introduced as a resource option in the *Plexos*® optimization model. Industrial programs were not developed or modeled based on the thought that industrial customers, by and large, will "selfinvest" in energy efficiency measures based upon unique economic merit *irrespective* of the existence of utility-sponsored program activity.

4.4.2 Achievable Potential (AP)

The amount of available EE is typically described in three sets: *technical* potential, *economic* potential, and *achievable* potential. The previously-cited EPRI report breaks down the achievable potential into a higher utility cost High Achievable Potential (HAP) and an Achievable Potential (AP). Briefly, the technical potential encompasses all known efficiency improvements that are possible, regardless of cost, and thus, whether 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 its 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; while 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. Both amounts are represented in this IRP as reductions to what would otherwise be the load forecast.

4.4.3 Evaluating Incremental Demand-Side Resources

The *Plexos*® model allows the user to input incremental CHP, EE, DG and EECO 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, a determination was made as to the potential level and cost of such incremental EE activity as well as the ability to expand current programs. Figure 21 and Figure 22 show the "going-in" make-up of projected consumption in I&M's residential and commercial sectors in the year 2018. It was assumed that the incremental programs modeled would be effective in 2018, due to the time needed to develop specific program cost and measures and receive regulatory approval to implement such programs.

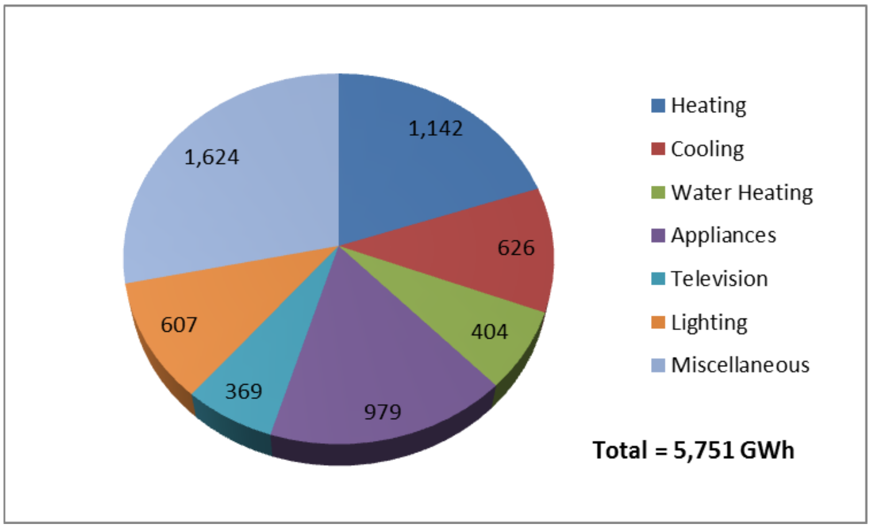

Figure 21. 2018 I&M Residential End-use (GWh)

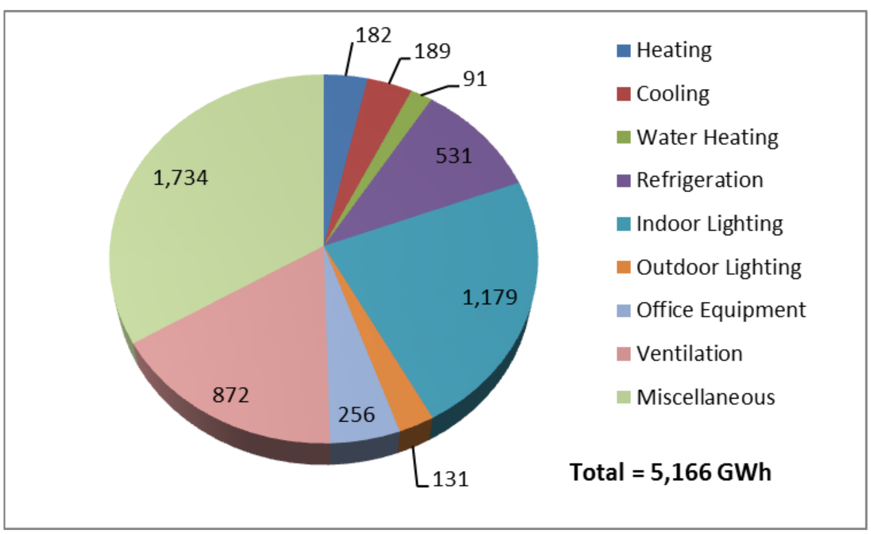

Figure 22. 2018 I&M Commercial End-use (GWh)

The current programs target certain end-uses in both sectors. Future incremental EE activity can further target those areas or address other end-uses. To determine which end-uses are targeted, and in what amounts, I&M looked at the previously-cited 2014 EPRI Report. This report provides comprehensive and fairly detailed 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 utilized this data to develop "bundles" of future EE activity for the demographics and weather-related impacts of its service territory. Table 10 and Table 11**,** from the EPRI Report, list the individual measure categories considered for both the residential and commercial sectors.

Table 10. Residential Sector Energy Efficiency (EE) Measure Categories

Central Air Conditioning	Programmable Thermostat	Storm Doors	Dehumidifier
Air-Source Heat Pumps	Water Heating	External Shades	Dishwashers
Ground-Source Heat Pumps	Faucet Aerators	Ceiling Insulation	Clothes Washers
Room Air Conditioning	Pipe Insulation	Foundation Insulation	Clothes Dryers
Air Conditioning Maintenance	Low-Flow Showerheads	Foundation Insulation	Refrigerators
Heat Pump Maintenance	Dishwashers (Domestic Hot Water)	Wall Insulation	Freezers
Attic Fan	Furnace Fans	Windows	Cooking
Furnace Fans	Lighting – Linear Fluorescent	Reflective Roof	Televisions
Ceiling Fan	Lighting – Screw-in	Reflective Roof	Personal Computers
Whole-House Fan	Enhanced Customer Bill Presentment	Duct Repair	Smart Plug Strips, Reduce Standby Wattage
Duct Insulation		Infiltration Control	

Table 11. Commercial Sector Energy Efficiency (EE) Measure Categories

Heat Pumps	Duct Insulation	Fans, Energy-Efficient Motors	Lighting – Screw-in
Central Air Conditioning	Water Heater	Fans, Variable Speed Control	High-Efficiency Compressor
Chiller	Water Temperature Reset	Programmable Thermostat	Anti-Sweat Heater Controls
Cool Roof	Computers	Variable Air Volume System	Floating Head Pressure Controls
Variable Speed Drive on Pump	Servers	Duct Testing and Sealing	Installation of Glass Doors
Economizer	Displays	HVAC Retro-commissioning	High-Efficiency Vending Machine
Energy Management System	Copiers Printers	Efficient Windows	Icemakers
Roof Insulation	Other Electronics	Lighting – Linear Fluorescent	Reach-in Coolers and Freezers

What can be derived from the tables is that the 2014 EPRI report has taken a comprehensive approach to identifying available EE measures. From this information, I&M has developed proxy EE bundles for both residential and commercial customer classes to be modeled within *Plexos®*. These bundles are based on measure characteristics identified within the EPRI report and I&M customer usage, and are shown in Section 4.4.3.1.

Table 12 and Table 13 list the energy and cost profiles of EE resource "bundles" for the residential and commercial sectors, respectively.

Table 12. Incremental Demand-Side Residential Energy Efficiency (EE) Bundle Summary

Bundle	Utility Installed Cost ($/kWh)	Yearly Potential Savings (MWh) 2018 - 2019	Yearly Potential Savings (MWh) 2020 - 2024	Yearly Potential Savings (MWh) 2025 - 2029	Yearly Potential Savings (MWh) 2030 - 2040	Bundle Life
Thermal Shell - AP	0.28	3,792	1,223	1,570	2,049	10
Thermal Shell - HAP	0.42	20,961	9,492	10,577	5,235	10
Water Heating - AP	1.76	10,532	2,399	2,752	2,796	14
Water Heating - HAP	2.52	26,372	13,718	16,647	9,532	14
Appliances - AP	0.26	17,640	2,139	1,816	1,476	16
Appliances - HAP	0.42	30,103	10,591	8,540	2,190	17
Heating/Cooling - AP	1.74	31,657	8,044	3,593	813	18
Heating/Cooling - HAP	2.60	17,163	2,607	2,902	1,450	17
Lighting - AP	0.11	84,764	3,390	2,707	1,700	30
Lighting - HAP	0.16	90,731	28,366	21,257	3,787	30

Table 13. Incremental Demand-Side Commercial Energy Efficiency (EE) Bundle Summary

Bundle	Utility Installed Cost ($/kWh)	Yearly Potential Savings (MWh) 2018 - 2019	Yearly Potential Savings (MWh) 2020 - 2024	Yearly Potential Savings (MWh) 2025 - 2029	Yearly Potential Savings (MWh) 2030 - 2040	Bundle Life
Heating/Cooling - AP	2.15	5,975	708	829	-	15
Heating/Cooling - HAP	3.22	2,267	547	101	-	15
Office Equipment - AP	0.42	12,755	2,106	1,937	1,620	7
Office Equipment - HAP	0.63	18,013	5,502	3,565	-	7
Indoor Lighting - AP	0.80	97,000	8,651	9,471	3,547	14
Indoor Lighting - HAP	1.14	46,723	13,834	8,088	1,649	15

As can be seen from the tables, each program has both AP and HAP characteristics. The development of these characteristics is based on the 2014 EPRI EE Potential report that has been previously referenced. This report further identifies Market Acceptance Ratios (MAR) and Program Implementation Factors (PIF) to apply to primary measure savings, as well as Application Factors for secondary measures. Secondary measures are not consumers of energy, but do influence the system that is consuming energy. The Thermal Shell, Water Heating and Commercial Cooling—in both AP and HAP programs—include secondary measures. The MAR and PIF are utilized to develop the incremental Achievable program characteristics and the MAR only is used to develop the incremental HAP program characteristics.

Each EE bundle shown in Table 12 and Table 13 is offered into the model as a stand-alone resource with its own unique cost of energy and potential energy savings. Should the model determine that all or a portion of a bundle is economical that bundle, along with its respective size, will be included in the portfolio of optimized resources. Once the Preferred Portfolio is determined I&M will consider the details of which EE bundles were selected to develop appropriate EE offerings for I&M customers which resemble the bundles selected by the model. Efforts to determine program attributes such as participant costs, penetration rates, and bill savings, prior to this point in time would be highly speculative and potentially inaccurate.

The overall cost effectiveness of the EE bundles offered into the model was approximated as part of this analysis. Table 14 details the Participant Cost Test (PCT), Ratepayer Impact Measure (RIM), Utility Cost Test (UCT) and Total Resource Cost (TRC) ratios[11] for each of the bundles shown in Table 12 and Table 13. For the purpose of determining these ratios each program was assumed to be implemented in 2018 and in-service for its maximum life. A

[11] Calculations are based on the *California Standard Practice Manual – Economic Analysis of Demand-Side Programs and Projects* (October 2001)

discount rate of 10% was assumed for all net present value calculations used in the cost test calculations.

Table 14. Energy Efficiency Bundle Cost Test Results

Sector	Bundle	PCT Ratio	RIM Ratio	TRC Ratio	UCT Ratio
Residential	Thermal Shell - AP	3.3	0.6	1.8	3.1
Residential	Thermal Shell - HAP	3.1	0.5	1.4	1.7
Residential	Cooling - AP	0.9	0.4	0.4	0.7
Residential	Cooling - HAP	1.1	0.3	0.3	0.4
Residential	Water Heating - AP	1.1	0.2	0.3	0.4
Residential	Water Heating - HAP	1.6	0.2	0.3	0.4
Residential	Appliances - AP	1.6	0.4	0.0	1.0
Residential	Appliances - HAP	1.9	0.3	0.5	0.3
Residential	Lighting - AP	9.4	0.4	0.3	6.9
Residential	Lighting - HAP	7.8	0.4	3.0	0.3
Commercial	Heating - AP	0.9	0.2	0.2	0.4
Commercial	Heating - HAP	1.1	0.2	0.2	0.2
Commercial	Cooling - AP	0.7	0.2	0.1	0.3
Commercial	Cooling - HAP	0.9	0.1	0.1	0.1
Commercial	Office Equipment - AP	1.6	0.3	0.6	1.0
Commercial	Office Equipment - HAP	1.7	0.3	0.5	0.6
Commercial	Indoor Lighting - AP	7.0	0.9	6.2	10.6
Commercial	Indoor Lighting - HAP	6.5	0.8	5.3	6.7

4.4.3.2 Electric Energy Consumption Optimization (EECO) Modeled

Potential future EECO circuits considered for modeling varied in relative cost and energy-reduction effectiveness. The circuits were grouped into 14 "tranches" based on the relative potential demand 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. Typically, a EECO tranche includes approximately 30-40 circuits. Table 15, details all of the tranches offered into the model and the respective cost and performance of each. The costs shown are in 2015 dollars.

Table 15. Electric Energy Consumption Optimization (EECO) Tranche Profiles

Tranche	No. of Circuits	Capital Investment	Annual O&M	Demand Reduction (kW)	Energy Reduction (MWh)
1	37	$12,358,000	$333,000	6,969	22,955
2	34	$11,356,000	$306,000	5,356	17,641
3	34	$11,356,000	$306,000	5,268	17,351
4	36	$12,024,000	$324,000	5,249	17,287
5	37	$12,358,000	$333,000	5,348	17,614
6	38	$12,692,000	$342,000	5,303	17,468
7	36	$12,024,000	$324,000	4,793	15,787
8	38	$12,692,000	$342,000	4,635	15,265
9	38	$12,692,000	$342,000	4,391	14,462
10	37	$12,358,000	$333,000	4,029	13,269
11	35	$11,690,000	$315,000	3,611	11,895
12	37	$12,358,000	$333,000	2,889	9,516
13	35	$11,690,000	$315,000	2,266	7,464
14	25	$8,350,000	$225,000	4,206	13,852

4.4.3.3 Demand Response (DR) Modeled

Additional levels of DR were not modeled as an incremental resource within this plan. However, DR associated with known and anticipated interruptible and real-time pricing initiatives have already been incorporated into I&M's future "going-in" capacity position, as described in Section 2.

4.4.3.4 Distributed Generation (DG) Modeled

Distributed Generation (DG) (i.e. residential rooftop solar) resources were evaluated assuming a residential rooftop solar resource, as this is the primary distributed resource. Solar has favorable characteristics in that it produces the majority of its energy at near-peak usage times. DG resources are included in the model at an assumed growth rate, depicted in Figure 11 in Section 3.4.6.1, based on the current level of federal incentives, future estimated costs of rooftop solar and historical rooftop solar additions.

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.

Historically, I&M's low cost of energy combined with the relatively high cost of natural gas, a primary fuel for cogeneration facilities, has made CHP uneconomical in I&M's service territory. I&M is occasionally approached by customers for help in evaluating CHP opportunities, but the Company's relatively low avoided costs have been a significant barrier to-date for any serious implementation consideration. During I&M's IRP stakeholder meetings, stakeholders suggested that I&M include a CHP resource option for Plexos to consider.

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 $1,800/kW and the assumed modeled full load heat rate is approximately 4,800 Btu/kWh. Additionally, the assumed capacity factor was 90%. Figure 23, below, illustrates the cost of the CHP resource as compared with other resources modeled, with the cost varying by the amount of generation produced by resource.

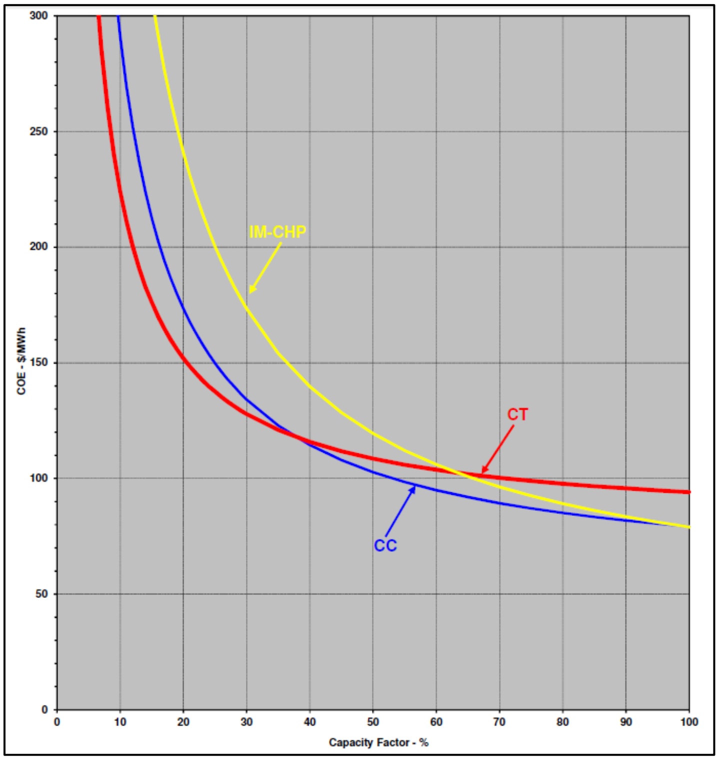

Figure 23. Combined Heat and Power Cost of Electricity (COE) vs. Capacity Factor

4.4.4 Avoided Cost Discussion

4.4.5 Avoided Generation Capacity Cost

The avoided costs estimates utilized in this IRP are discussed in Section 4.3. The avoided generation capacity cost utilized in this analysis is shown in Figure 17.

4.4.6 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.

4.4.7 Avoided Distribution Capacity Cost

The distribution system is planned, constructed, and operated to serve not only the load physically connected to I&M's wires, but also to operate adequately and reliably with generation and transmission connected to the distribution system.

The distribution system must have the capacity to reliably carry generation resources to various load centers and customers. Expansions of the distribution system are location-specific and dependent upon the particular circumstances of load, interconnected transmission, and connected generation at each location. The concept of distribution-related avoided cost is ever changing, based on the location being considered.

Because distribution expansion is so dependent upon location and factors beyond the Company's control, such as generation of others, local customer load changes and demand management, and local customer load diversity, it is nearly impossible to determine a distribution-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.

4.4.8 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 15 and Figure 16.

4.5 Identify and Screen Supply-side Resource Options

4.5.1 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. The options assumed to be available for modeling analyses for I&M are presented in Table 16.

When applicable, I&M may take advantage of economical 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.

4.5.2 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 G. To reduce the 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 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 the *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. Utilizing 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, AEP provides current estimates to the planning process. Table 16 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 16. New Generation Technology Options with Key Assumptions

Type	Capability (MW)(a)	Emission Rates SO2 (lb/mmBtu)	NOx (lb/mmBtu)	CO2 (lb/mmBtu)	Capacity Factor (%)	Overall Availability (%)
Base Load						
Nuclear	1,610	0.00	0.00	0.00	90	94
Base Load (90% CO2 Capture New Unit)						
Pulv. Coal (Ultra-Supercritical) (PRB) (d)	460	0.12	0.07	20.5	85	90
IGCC "F" Class (PRB) (d)	530	0.01	0.06	20.5	85	88
Base / Intermediate (b)						
Combined Cycle (2X1 "F" Class)	640	0.0007	0.009	116.0	60	89
Combined Cycle (2X1 "G" Class, w/duct firing & evap coolers)	780	0.0007	0.007	116.0	60	89
Peaking						
Combustion Turbine (2 - "E" Class) (b)	170	0.0007	0.009	116.0	3	93
Combustion Turbine (2 - "F" Class, w/evap coolers) (b)	430	0.0007	0.009	116.0	25	93
Aero-Derivative (2 - Large Machines) (b)	200	0.0007	0.007	116.0	25	95
Aero-Derivative (2 - Small Machines) (c)	90	0.0007	0.093	116.0	25	96
Recip Engine Farm (3 Engines)	50	0.0007	0.018	116.0	36	96

Notes: (a) Capability at Standard ISO Conditions at 1,000 feet above sea level.
(b) Includes Dual Fuel capability and SCR environmenttal installation
(c) Includes Dual Fuel capability
(d) PRB = Powder River Basin Coal

4.5.3 Base/Intermediate Alternatives

Coal and Nuclear base-load options were evaluated by I&M but were not included in the ultimate *Plexos*® resource optimization modeling analyses. The forecasted difference between I&M's load forecast and existing resources are such that a large, central generating station would not be required. In addition, for coal generation resources, the proposed EPA NSPS rulemaking effectively makes the construction of new coal plants environmentally/economically impractical due to the implicit requirement of Carbon Capture and Sequestration (CCS) technology. For new nuclear construction, it is financially impractical since it would potentially require an investment of, minimally, \$6,000/kW.

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 have 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' staffs have made strides to improve ramp rates, regulation capability, and reduce downturn (minimum load capabilities). As the fleet continues to age and subcritical units are retired, other generation dispatch alternatives and new generation will need to be considered to cost effectively meet this duty cycle's operating characteristics.

4.5.3.1 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 Heat Recovery Steam Generator (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 45-60% Lower Heating Value), low emission levels, small footprint and shorter construction periods than coal-based plants. In the past 8 to 10 years, NGCC plants were often selected to meet new intermediate and certain base-load needs. NGCC plants may be designed with the capability of being "islanded" which would allow them, in concert with an associated diesel generator, to perform system restoration ("black start") services. 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.

4.5.4 Peaking Alternatives

Peaking generating sources provide needed capacity during extreme 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" resources 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.

4.5.4.1 Simple Cycle Natural Gas Combustion Turbines (NGCT)

In "industrial" or "frame-type" Natural Gas Combustion Turbine (NGCT) 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 simple cycle combustion turbine 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.

4.5.4.2 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 7EA frame machine requires 20 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 on the order of 20% 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 increase; b) base-load generation processes become more complex limiting their ability to load-follow and; c) 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 the aeroderivative units.

Some of the better known AD vendors and their models include GE's LM series, Pratt & Whitney's FT8 packages, and the Rolls Royce Trent and Avon series of machines.[12]

4.5.4.3 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 (SI) engines and post 2000 sales of natural gas-fired generators have remained above 10% of total units sold worldwide.

[12] Turbomachinery International, Jan/Feb. 2009; Gas Turbine World; EPRI TAG.

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. The RE generators have high efficiency, flat heat rate curves and rapid response makes this technology very well suited for peaking and intermediate load service and as back up to intermittent generating resources. Additionally, the fuel supply pressure required is in the range of 40 to 70 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 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 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.

The main North American suppliers for utility-scale natural gas-fired RE most recently have been Caterpillar and Wartsila[13].

4.5.5 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 recent past, 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 (PV) and wind turbine manufacturing have reduced both installed and ongoing costs.

[13] Technical Assessment Guide (TAG) Power Generation and Storage Technology Options, 2012; Electric Power Research Institute.

4.5.5.1 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 power a turbine — produces electricity on a large scale and is similar to traditional centralized supply assets in that way. Photovoltaics produce electricity on a smaller scale (typically 2kW to 20MW per installation) and can be distributed throughout the grid.

The cost of installed solar projects has declined considerably in the past decade and is expected to continue to decline, as shown in Figure 24. 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.

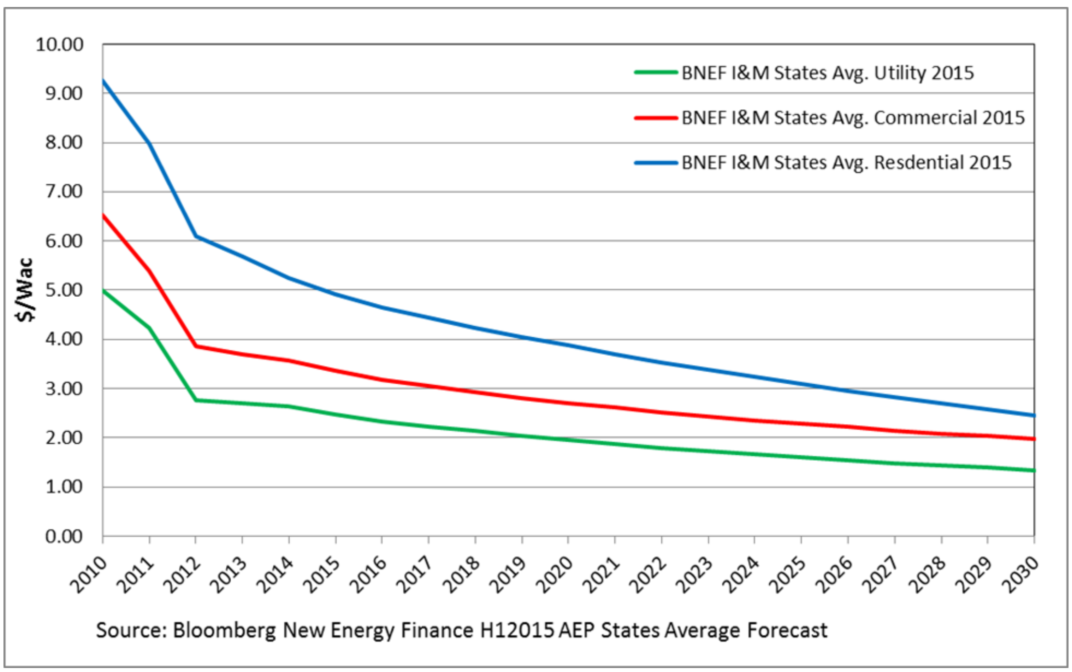

Figure 24. Recent and Forecasted Solar Installed Costs for I&M Territory (Excl. Fed & State Incentives)

Not only are large-scale solar plants getting less expensive, the costs to install solar panels in distributed locations, often on a rooftop, are lessening as associated hardware, such as inverters, racks, and wiring bundles become standardized. If the projected cost declines materialize, both distributed and large-scale solar projects will be economically justifiable in the future.

Large-scale solar plants require less lead time to build than fossil plants. There is not a defined limit to how much utility solar can be built in a given time. However, in practice, solar facilities are not added in an unlimited fashion.

Solar resources were considered available resources 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 50MWac[14] of nameplate capacity starting in 2016. To provide some context, a typical commercial installation is 50 kW and effectively covers the surface of a typical big box retailer's roof. A 50MW large-scale solar farm is assumed to consume nearly 350 acres, or 1,000 big box retailer roofs. 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. This 50MWac annual threshold recognizes that there is a practical limit as to the number of sites that can be identified, permitted and constructed by I&M in a given year. 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' useful capacity is less than its nameplate rating. This IRP assumes solar resources will have capacity valued at 38% of nameplate rating. This value is unchanged by PJM's Capacity Performance construct.

4.5.5.2 Wind

Large-scale wind energy is generated by turbines ranging from 1.0 to 2.5MW, with a 1.5MW turbine being the most common size used in commercial applications today. 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 its proximity to a transmission system with available capacity 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),

[14] 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.

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 very remote locations, which forces the electricity to be transmitted long 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 was considered under various 'blocks' or 'tranches' for each year. There are two tranches of wind with different pricing. The first tranche of wind resources, Tranche A was modeled as a 150MW block with a Levelized Cost Of Energy (LCOE) with the Production Tax Credit (PTC) of $40/MWh in 2015 and a 45% capacity factor load shape. In 2017, after the expiration of the PTC, the LCOE of Tranche A increases to $63/MWh in nominal dollars with prices increasing 1%/year through 2035. The second tranche of wind resources, Tranche B, was modeled as a 150MW block with a LCOE with the PTC of $50/MWh in 2015$ and a 40% capacity factor load shape. In 2017, after the assumed expiration of the PTC, the LCOE of Tranche B increases to $73/MWh in nominal dollars with prices increasing 2%/year through 2035. Both tranches were assigned a capacity value of 0% of nameplate rating as a result of the PJM Capacity Performance construct. Wind prices were developed based on the U.S. DOE's Wind Vision Report.[15]

The expected magnitude of wind resources available per year was limited to 300MW (nameplate) with a limit of 1,400MW nameplate, incremental to that which is currently planned. This cap is based on the DOE's Wind Vision Report chart on page 12 of the report which suggests from numerous 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 capacity resources as wind-powered by 2035. Figure 25, below, illustrates the two tranches of wind resources modeled and the relative LCOE for each tranche.

[15] *WindVision: A New Era for Wind Power in the United States* (2015). Retrieved from http://www1.eere.energy.gov/library/default.aspx?Page=9

Figure 25. LCOE (nominal $/MWh) for Wind Resource Tranches Included in I&M Model

4.5.5.3 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 hydro prohibitive at this time. As such, no incremental hydroelectric resources were considered in this IRP.

4.5.5.4 Biomass

Biomass is a term that typically includes organic waste products (sawdust or other wood waste), organic crops (corn, switchgrass, 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 through the utilization of the biomass fuel in 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.

4.6 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, 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.

4.6.1 Optimization of Expanded DSM Programs

As described in Section 4.4.3, EE 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 (see Table 4-3).

4.6.2 Optimization of Other Demand-Side Resources

Customer-sited DG, specifically rooftop solar, was not modeled. Instead, reductions in energy use and peak demand were built into the load forecast based on the adoption rates discussed in Section 3.4.6.1. DG installation costs to I&M were zero, with all costs paid by the customer.

CHP was modeled as a high-thermal efficiency, NGCT facility, as described in Section 4.4.3.6.

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-specific 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 that minimize the CPW of a planning entity's generation-related variable and fixed costs over a long-term planning horizon.

Plexos® accomplishes this by 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 a 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's generating units. This includes fuel, start-up, consumables, market replacement cost of emission allowances, and/or carbon 'tax,' and variable O&M costs;
- a 'netting' of the production revenue made into the PJM power market from I&M's generation resource sales *and* the cost of energy – based on unique load shapes from PJM purchases necessary to meet I&M's load obligation.

Plexos® executes the objective function described above while abiding by the following possible constraints:

- Minimum and maximum reserve margins;
- Resource addition and retirement candidates (*i.e.*, maximum units built);
- Age and lifetime of generators;
- 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 compose the objective function and constraints are considered in the development of an integrated plan that best fits the utility system being analyzed. *Plexos*® does not develop a full regulatory Cost-of-Service (COS) profile. Rather, it typically considers only the relative load and generation COS *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 spends for transmission interconnection costs.

5.1.1 Key Input Parameters

Two of the major underpinnings in this process 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. Both forecasts were created internally within AEP. The load forecast was created by the AEP Economic Forecasting organization, while the long-term commodity pricing forecast was created by the AEP Fundamental Analysis group. 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.

Other critical input parameters include the installed cost of replacement capacity alternative options, as well as the attendant operating costs associated with those options; data which was sourced from the AEP Engineering Services organization.

5.2 *Plexos*® Optimization

5.2.1 Modeling Options and Constraints

The LT Plan®, LP optimization algorithm considers modeled constraints 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. It is a practical limitation that 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 duty cycle "families" (base-load, intermediate, and peaking).

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 will be considered that will determine the ultimate technology type (e.g., choices for peaking technologies).

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 2018 due to the anticipated period required to approve, site, engineer and construct, from:
  - NGCT units consisting of two "E" class turbines rated at 176MW at standard conditions and 179MW at summer conditions.
  - AD units (2) at 92MW at standard conditions and 87MW at summer conditions.
- *Intermediate* capacity was modeled, effective in 2020 due to anticipated period required to approve, site, engineer and construct, from:
  - NGCC (2x1 "G" class turbine with duct firing and evaporative inlet air cooling) facility, rated at 779MW at standard conditions and 870MW at summer conditions. These units were offered to the model at two levels: a 50% stake (435MW summer capacity) and a 100% stake. The 50% stake assumes I&M coordinates the addition of this resource with other parties.
- Wind resources were made available up to 300MW annually consisting of two tranches of 150MW with initial levelized costs of $63/MWh, and $73/MWh (without PTC). 1,400MW of incremental nameplate wind was made available.
- Large-scale solar resources were made available up to 50MW annually of incremental nameplate capacity, with a 2015 installed cost of $2,480 per MW.
- DG, in the form of distributed solar resources in 5kW sizes, was made available in amounts equal to approximately 5% of annual increases.
- CHP resources were made available in 15MW blocks, with an overnight installed cost of $1,800/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, were made available in 16 unique "bundles" of residential and commercial measures considering cost and performance parameters for both HAP and AP categories.

- EECO was available in 14 tranches of varying installed costs and number of circuits/sizes ranging from a low of 2MW, up to 7MW.

5.2.2 Optimization Cases

The key decision to be made by I&M during the planning period is how to fill the resource need identified. Four separate cases were analyzed using *Plexos*®. These cases are described below in Table 17.

Table 17. Description of Cases used for Optimization

Case	Description
Steady State	• Maintains Rockport and Cook plants by investing in environmental control system upgrades as required • Meets increasing energy demand through economically selected supply- and demand-side resources • Adds natural gas facilities as required to meet capacity obligations
Fleet Modification	• Removes one Rockport unit in 2022 when impacts of carbon legislation take effect • Replace Rockport capacity with NGCC facility • Meet increasing energy needs through solar, wind, CHP and EE programs
Fleet Modification Prime	• Removes one Rockport unit in 2022 when impacts of carbon legislation take effect • Replace capacity with limited NGCC capacity • Extended ITC and increased annual limit for solar resources
New Carbon Free	• Removes one Rockport unit in 2022 and the second Rockport unit in 2025 • Replacement capacity from NGCTs limited to 66% of capacity need • Extended 30% ITC and increased annual build limit for solar

Each case was then analyzed under five different of fundamental pricing scenarios, as follows:

1. Base pricing
2. High Band pricing
3. Low Band pricing
4. High CO_2 (or High Carbon) pricing
5. No CO_2 (or No Carbon) pricing

Two sensitivity evaluations were conducted for the Steady State case, under the Base commodity pricing scenario, but using two different long-term load (and peak demand) forecasts:

1. High Load sensitivity
2. Low Load sensitivity

An additional sensitivity evaluation was created under the Base pricing *and* Base load conditions. This sensitivity was offered to assess the prospect of *not* retrofitting Rockport Unit 2 by December, 2019—as required under the Modified Consent Decree—but rather retiring the unit by the end-of-2019 date:

1. 'Rockport Unit 2 Early Removal from Service'

Table 18, below, lists all 23 combinations of scenarios and conditions which were optimized as part of I&M's IRP.

Table 18. Full List of Cases and Scenarios Optimized as part of I&M IRP

Case	Optimization Scenarios
Steady State	• Base Pricing • High Band Pricing • Low Band Pricing • High CO_2 Pricing • No CO_2 Pricing • High Load (Sensitivity) • Low Load (Sensitivity)
Fleet Modification	• Base Pricing • High Band Pricing • Low Band Pricing • High CO2 Pricing • No CO2 Pricing
Fleet Modification Prime	• Base Pricing • High Band Pricing • Low Band Pricing • High CO2 Pricing • No CO2 Pricing
New Carbon Free	• Base Pricing • High Band Pricing • Low Band Pricing • High CO2 Pricing • No CO2 Pricing
Rockport Unit 2 Early Retirement	• Base Pricing

Finally, risk, or stochastic, analyses were then performed on each of the four initial scenarios.

5.2.2.1 Optimization Modeling Results of Base Pricing Scenarios

The analysis for each of the scenarios above results in a portfolio of supply-side and demand-side resources for the Company. Each case was analyzed under each of the five commodity pricing conditions, listed above and discussed in Section 4.3.1. The tables which follow below only contain the results of the Base pricing scenarios. The results from the optimization of the scenarios under all conditions were reviewed and considered before preparing I&M's Preferred Portfolio. Optimization results not included below can be found in Exhibit F of the Appendix.

For each of the four Base pricing scenarios the portfolio of cumulative resources added throughout the planning period is shown below in Table 19. These resources are those which are in addition to I&M's existing portfolio.

Table 19. Cumulative PJM Capacity Additions (MW) for Four Initial Base Cases

Base Cases		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
1. Steady State	Base/Intermediate															418	418	418	418	418	418
	Peaking																				
	Solar (Firm)														11	11	11	27	46	65	84
	Solar (Namplate)														30	30	30	70	120	170	220
	Wind (Firm)																				
	Wind (Namplate)											150	300	450	600	750	900	1,050	1,200	1,350	1,350
	CHP																				
	EE			8	16	18	19	21	23	23	25	27	28	30	32	32	32	33	33	33	34
	EECO	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
	DG			0.4	0.4	0.4	0.4	0.4	0.8	0.8	0.8	0.8	1.1	1.1	1.1	1.1	1.5	1.5	1.5	1.9	1.9
2. Fleet Modification	Base/Intermediate							835	1,253	1,253	1,253	1,253	1,253	1,253	1,253	1,253	1,253	1,253	1,253	1,253	2,088
	Peaking																				
	Solar (Firm)																				
	Solar (Namplate)																				
	Wind (Firm)																				
	Wind (Namplate)											150	300	450	600	750	900	1,050	1,200	1,350	1,350
	CHP																				
	EE			16	30	36	40	44	46	46	47	49	50	51	53	53	53	54	54	54	55
	EECO	6	6	6	6	6	6	14	14	14	14	14	14	14	14	14	14	14	14	14	14
	DG			0.4	0.4	0.4	0.4	0.4	0.8	0.8	0.8	0.8	1.1	1.1	1.1	1.1	1.5	1.5	1.5	1.9	1.9
3. Fleet Modification Prime	Base/Intermediate							835	835	835	835	835	835	835	835	835	835	835	835	835	1,670
	Peaking																				
	Solar (Firm)										11	11	11	23	72	129	148	156	209	266	323
	Solar (Namplate)										30	30	30	60	190	340	390	410	550	700	850
	Wind (Firm)																				
	Wind (Namplate)											150	300	450	600	750	900	1,050	1,200	1,350	1,350
	CHP							54	68	68	95	122	136	136	136	136	136	136	136	136	136
	EE			10	21	23	25	27	29	30	36	39	42	44	45	47	47	48	48	48	48
	EECO	6	6	6	6	6	6	14	20	25	25	25	25	25	25	25	25	25	25	25	25
	DG			0.4	0.4	0.4	0.4	0.4	0.8	0.8	0.8	0.8	1.1	1.1	1.1	1.1	1.5	1.5	1.5	1.9	1.9
4. New Carbon Free	Base/Intermediate																				
	Peaking							430	430	430	1,289	1,289	1,289	1,289	1,289	1,289	1,289	1,289	1,289	1,289	1,289
	Solar (Firm)	19	76	133	190	247	304	361	418	475	532	551	570	578	627	684	707	707	745	760	760
	Solar (Namplate)	50	200	350	500	650	800	950	1,100	1,250	1,400	1,450	1,500	1,520	1,650	1,800	1,860	1,860	1,960	2,000	2,000
	Wind (Firm)																				
	Wind (Namplate)											150	300	450	600	750	900	1,050	1,200	1,350	1,350
	CHP							27	27	27	136	136	136	136	136	136	136	136	136	136	136
	EE	0	0	17	33	44	54	65	75	85	100	111	121	132	143	150	156	162	168	174	180
	EECO	6	6	12	20	25	31	37	42	47	53	57	62	62	62	65	69	72	72	72	72
	DG			0.4	0.4	0.4	0.4	0.4	0.8	0.8	0.8	0.8	1.1	1.1	1.1	1.1	1.5	1.5	1.5	1.9	1.9

Base/Intermediate=NGCC; Peaking=NGCT, AD; CHP=Combined Heat and Power; EE=Energy Efficiency; VVO=Volt VAR Optimization; DG=Distributed Generation

The Steady State portfolio includes the addition of wind and solar resources beginning in 2026 and 2029, respectively. An NGCC facility is added in 2030. EE, EECO, and DG resources are added throughout the planning period, beginning in 2016. The Fleet Modification portfolio calls for additional NGCC generation in 2022, which corresponds with Rockport Unit 2's removal from service in this scenario. The optimized Fleet Modification portfolio calls for no new solar generation. The Fleet Modification Prime portfolio also shows NGCC generation being added in 2022, however because this scenario includes a limit on NGCC resources the portfolio also includes large amounts of solar generation and CHP. The New Carbon Free scenario – which considers the removal from service of both Rockport units – calls for substantial NGCT generation, as well a very large amount of solar energy. The New Carbon Free portfolio also includes the largest amount of EE out of all four initial scenarios.

5.2.2.2 Optimization Modeling Results of Load Sensitivities

Table 20 shows the company's required Steady State portfolio resources under the High and Low Load sensitivities. The High Load sensitivity calls for additional Base/Intermediate level natural gas generation, beginning in 2022, than in Steady State Base scenario analyzed above. Also, this High Load portfolio includes solar resources beginning in 2016, although the total solar added is less than the Steady State Base scenario. The Low Load sensitivity's portfolio does not include any new natural gas generation until 2035, after Cook Unit 1's scheduled retirement in 2034. Both the High and Low Load sensitivities result in quantities of wind, EE, and EECO resources comparable to the commodity pricing scenarios above in Table 19.

Table 20. Cumulative PJM Capacity Additions (MW) for Load Sensitivities

Load Sensitivities		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
6. High Load	Base/Intermediate							418	418	418	418	418	418	418	418	835	835	835	835	835	1,670
	Peaking																				
	Solar (Firm)	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19
	Solar (Namplate)	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
	Wind (Firm)																				
	Wind (Namplate)											150	300	450	600	750	900	1,050	1,200	1,350	1,350
	CHP																				
	EE			8	16	18	19	21	23	23	24	26	27	28	30	30	30	31	31	31	32
	EECO	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
	DG			0.4	0.4	0.4	0.4	0.4	0.8	0.8	0.8	0.8	1.1	1.1	1.1	1.1	1.5	1.5	1.5	1.9	1.9
7. Low Load	Base/Intermediate																				835
	Peaking																				
	Solar (Firm)																		4	23	42
	Solar (Namplate)																		10	60	110
	Wind (Firm)																				
	Wind (Namplate)											150	300	450	600	750	900	1,050	1,200	1,350	1,350
	CHP																				
	EE			8	16	18	19	21	23	23	24	26	27	28	30	31	33	34	35	36	37
	EECO	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
	DG			0.4	0.4	0.4	0.4	0.4	0.8	0.8	0.8	0.8	1.1	1.1	1.1	1.1	1.5	1.5	1.5	1.9	1.9

Base/Intermediate=NGCC; Peaking=NGCT, AD; CHP=Combined Heat and Power; EE=Energy Efficiency; VVO=Volt VAR Optimization; DG=Distributed Generation

5.2.2.3 Optimization Modeling Results of Rockport 2 Retirement Sensitivity

During the June 2015 public advisory meeting a stakeholder requested that I&M analyze a scenario that retired Rockport 2 prior to installing an SCR in 2019 and compare that to a scenario where the SCR was installed on Rockport 2 in 2019 but the Rockport 2 lease was not extended beyond 2022. I&M performed this analysis and the results (shown in Table 22) confirm that adding the SCR to Rockport Unit 2 in 2019 is a lower cost option than retiring Rockport Unit 2, even if the Rockport 2 lease is not renewed. The primary driver of this result is that the lease termination payment that I&M would be assessed if Rockport Unit 2 was retired in 2019 significantly exceeds the estimated cost of the SCR. In addition, retiring Rockport Unit 2 would result in the loss of three years of market revenues which offset I&M customer load costs.

5.2.3 Preferred Portfolio

Each of the optimized portfolios above, as well as those in Exhibit F provide insight into a potential alternative mix of resources for the future. This mix, referred to as the Preferred Portfolio, is shown below in Table 21. In comparison to the Steady State, Base scenario the Preferred Portfolio includes the following:

- Delayed installation of NGCC capacity until 2035[16]
- Increased levels of large-scale solar
- Earlier adoption of large-scale solar and wind resources
- CHP resources beginning in 2020

Table 21. Cumulative PJM Capacity Additions (MW) for Preferred Portfolio

Preferred Portfolio		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Base Commodity, Base Load	Base/Intermediate																				1,253
	Peaking																				
	Solar (Firm)					8	19	19	19	19	38	57	76	95	114	133	152	171	190	209	228
	Solar (Namplate)					20	50	50	50	50	100	150	200	250	300	350	400	450	500	550	600
	Wind (Firm)																				
	Wind (Namplate)					150	150	150	150	300	450	600	750	900	1,050	1,200	1,350	1,350	1,350	1,350	1,350
	CHP					14	14	14	14	14	14	27	27	27	27	27	27	27	27	27	27
	EE			8	16	18	19	21	23	23	25	27	28	30	32	32	32	33	33	33	34
	EECO	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
	DG			0.4	0.4	0.4	0.4	0.4	0.8	0.8	0.8	0.8	1.1	1.1	1.1	1.1	1.5	1.5	1.5	1.9	1.9

Base/Intermediate=NGCC; Peaking=NGCT, AD; CHP=Combined Heat and Power; EE=Energy Efficiency; VVO=Volt VAR Optimization; DG=Distributed Generation

[16] During the September 28, 2015 Stakeholder Meeting I&M indicated this NGCC facility would be added in 2030. After further evaluation, I&M determined that it could meet PJM capacity requirements through 2034 without this facility due to the addition of solar and CHP resources.

In the Preferred Portfolio new Base/Intermediate capacity is not added until 2035, after the scheduled retirement of Cook Unit 1 in 2034. Large-scale solar resources are added to the portfolio beginning in 2020, as opposed to 2029 in the Steady State plan. A total of 600MW nameplate is added in the Preferred Portfolio, nearly three times the amount of the Steady State portfolio. The Preferred Portfolio accelerates the addition of wind resources from 2026 to 2020, and includes a total of 27MW of CHP by 2035.

The cost of the Preferred Portfolio was compared to the other evaluated portfolios to determine if the incremental cost associated with accelerating renewable resources was reasonable. This discrete analysis shows the cumulative present value cost of all portfolios under each pricing scenario, compares the relative cost, on both a levelized "bill impact" and cumulative present worth basis, of each portfolio to the lowest cost portfolio under each pricing scenario. As can be seen in Table 22, the Preferred Portfolio, under all but one pricing scenario, is less than one dollar/month (levelized basis) more expensive than the lowest cost portfolio for that scenario. This Preferred Portfolio has the benefit of adding capacity in small increments, which limits large capital outlays for new generation, which helps maintain stable rates.

Table 22. Incremental Cost of Portfolios Over Lowest Cost Option

Cumulative Present Worth 2016-2045 *Plus* End Effects ($ in Millions)

Levelized Annual Bill Impact in $'s

	Base Pricing	No Carbon	High Pricing	Low Pricing	High Carbon	RP1	RP2
Steady State	Lowest Cost	Lowest Cost	Lowest Cost	19	Lowest Cost	Operate	Operate
Levelized Annual Bill Impact				*$ 0.66*			
Cum. Present Value of Rev Rqmnt	*$12,296*	*$11,798*	*$12,041*	*$12,762*	*$13,096*		
Fleet Modification	174	333	331	Lowest Cost	5	Operate	Remove 2022
Levelized Annual Bill Impact	*$ 6.19*	*$ 11.82*	*$ 11.74*		*$ 0.18*		
Cum. Present Value of Rev Rqmnt	*$12,471*	*$12,131*	*$12,372*	*$12,744*	*$13,101*		
Fleet Modification Prime	1,186	685	541	311	218	Operate	Remove 2022
Levelized Annual Bill Impact	*$ 42.10*	*$ 24.30*	*$ 19.21*	*$ 11.03*	*$ 7.75*		
Cum. Present Value of Rev Rqmnt	*$13,483*	*$12,483*	*$12,582*	*$13,055*	*$13,315*		
New Carbon Free	3,179	3,303	3,073	2,638	2,361	Remove 2025	Remove 2022
Levelized Annual Bill Impact	*$ 112.83*	*$ 117.24*	*$ 109.06*	*$ 93.63*	*$ 83.81*		
Cum. Present Value of Rev Rqmnt	*$15,476*	*$15,101*	*$15,114*	*$15,382*	*$15,458*		
Fl. Mod. w/No RP2 SCR	639					Operate	Remove 2019
Levelized Annual Bill Impact	*$ 22.69*						
Cum. Present Value of Rev Rqmnt	*$12,936*						
Preferred Plan	251	359	238	65	226	Operate	Operate
Levelized Annual Bill Impact	*$ 8.90*	*$ 12.72*	*$ 8.44*	*$ 2.30*	*$ 8.01*		
Cum. Present Value of Rev Rqmnt	*$12,547*	*$12,156*	*$12,278*	*$12,809*	*$13,322*		

Assumptions

Steady State: RP1&2 SCR, RP1&2 FGD
Fleet Modification: RP1 SCR-FGD, RP2 SCR Only RP2 No lease renewal 2022, replace with NGCCs
Fleet Modification Prime: RP1 SCR-FGD, RP2 SCR Only RP2 No lease renewal 2022, Replace w/NGCC and Renewable Energy/EE
New Carbon Free: RP1&2 SCR, RP1 Removed in 2025, RP2 No lease renewal 2022, Replace with Renewable Energy/EE and limited NGCT's
Fl. Mod.w/ No RP2 SCR; RP1 SCR-FGD, RP2 Removed 2019 (no SCR added)
Preferred Plan; Same as Steady State, but adds wind and solar at higher levels beginning in 2020, adds CHP
Levelized Annual Bill Impact over entire study period based on 1,000 kWh/month in $
Cum. Present Value of Rev. Rqmnt; is the cumulative present value of all variable and incremental fixed cost over entire study period

The Preferred Portfolio offers I&M significant flexibility should future conditions differ considerably from assumptions. For example, as EE programs are implemented, I&M will gain insight into customer acceptance and develop 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. Flexibility is also achieved by the delayed need for natural gas capacity. By making small capacity additions over the next decade I&M will be able to adapt to changing market conditions for resources such as renewables.

I&M does not anticipate any significant concerns to develop over its ability to finance the additions identified in the Preferred Portfolio. I&M will seek approval from the IURC and the Michigan Public Service Commission prior to commencing large capital projects such as the Rockport SCR and FGD retrofits. This will ensure that such projects are reasonable and in the public interest, and as such I&M would receive appropriate cost recovery. I&M will also request authorization to enter into power purchase contracts, or to self-build, renewable energy projects prior to the commencement of those contracts/projects as well.

5.2.3.1 Energy Efficiency (EE), Electric Energy Consumption Optimization (EECO) and Distributed Generation (DG) Results

In the Preferred Portfolio, incremental EE resources were selected. Overall, including current activity, projected residential programs are providing 70MW of capacity by the end of the planning period. The program providing the majority of the savings is Residential Lighting. Figure 26, below, illustrates I&M's EE profile with respect to non-DSM EE, existing programs, and new, or incremental, programs throughout the planning period.

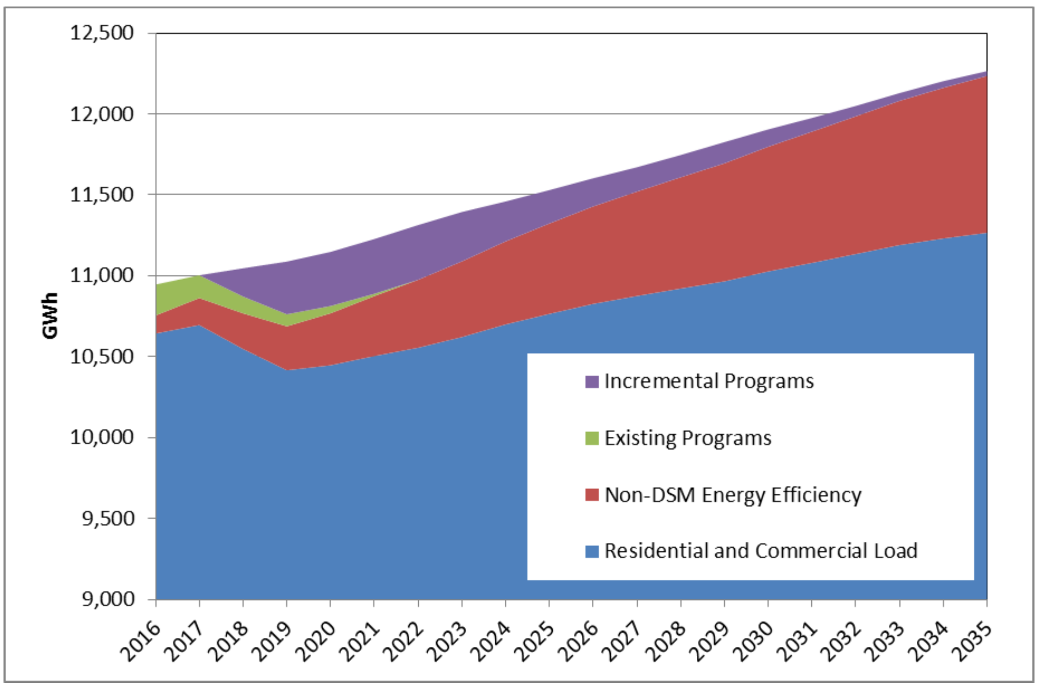

Figure 26. I&M Energy Efficiency Energy Profile over Planning Period (2016-2035)

The Preferred Portfolio includes 6MW of EECO in 2016 from a pilot program currently being installed in I&M's service territory.

DG, or rooftop solar, was included as a resource based on historical additions for I&M and the continued decline in the installed cost of solar resources. The rate and quantity of DG additions is illustrated in Figure 11 of Section 3.4.6.1.

Two CHP units were selected over the planning period adding a total of 27MW of capacity. The locations and customers' of these two resources are not known at this time. I&M will continue to work with its' customers to identify feasible and economical CHP opportunities.

5.2.4 Future CO_2 Emissions Trending – Preferred Portfolio

Figure 27 through Figure 30 offer a long-term view of the I&M "total company" and state-specific projected CO_2 emissions—under both an "(intensity) rate" and "mass-based" view—for the IRP Preferred Portfolio. Such projected emission levels are identified as of the interim (2022 through 2029) as well as final (2030 and beyond) implementation periods set forth in the Final CPP. These charts offer a summary depiction of I&M's trends—versus a 2012 (Actual) baseline—regarding CO_2 emissions that result from actions undertaken as part of this IRP process.

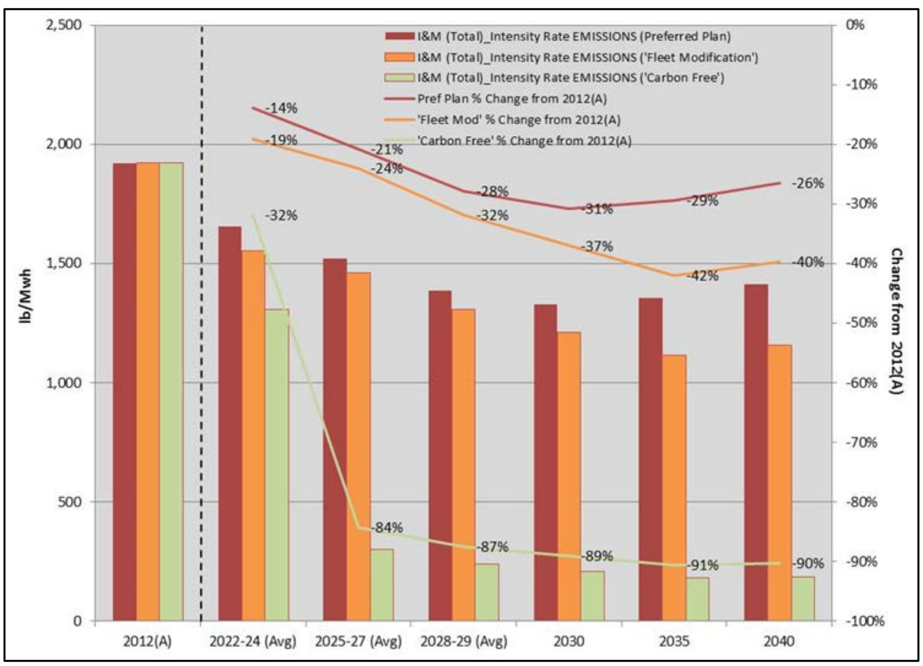

Figure 27. I&M Preferred Portfolio Projected CO_2 Emissions Intensity Rate

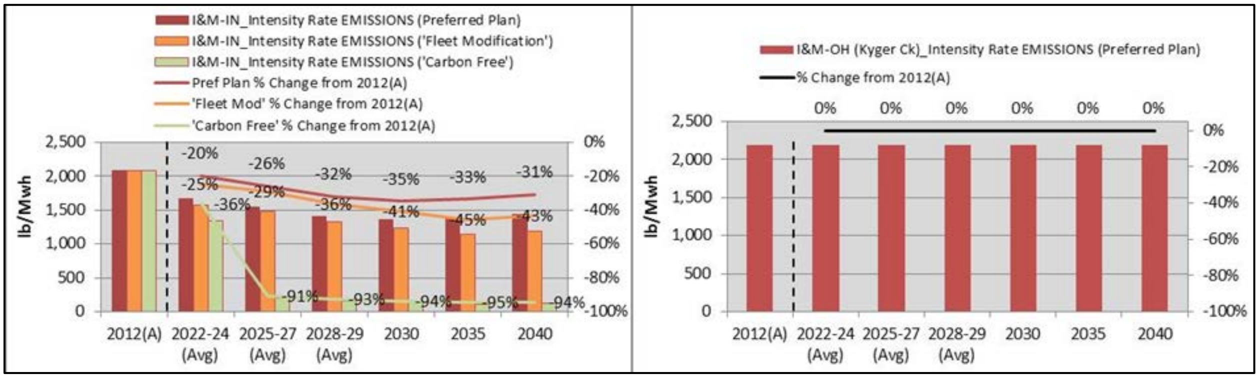

Figure 28. I&M State Specific Project CO_2 Emissions Intensity Rates

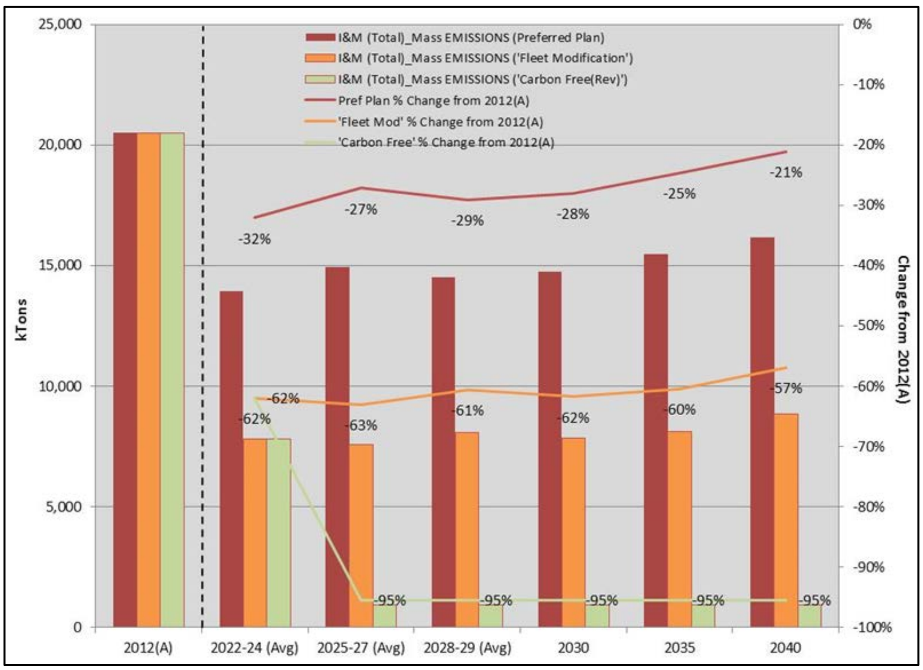

Figure 29. I&M Preferred Portfolio Projected CO_2 Mass Emissions

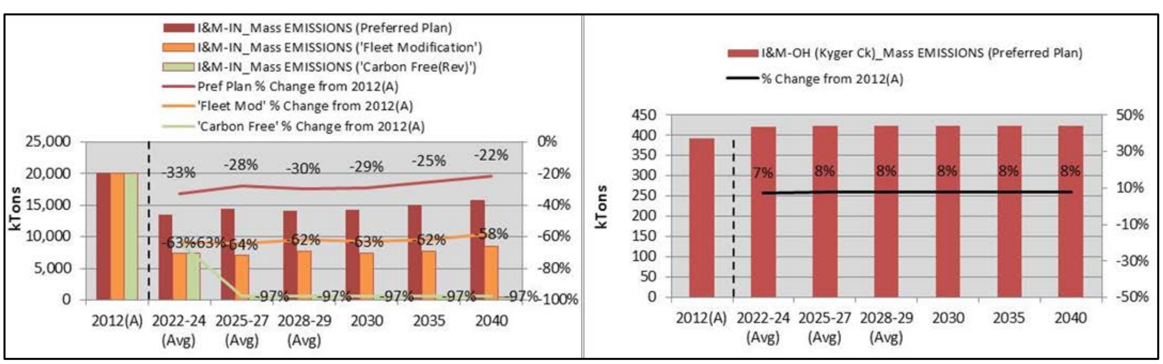

Figure 30. I&M State Specific Preferred Portfolio Projected CO_2 Mass Emissions

5.3 Risk Analysis

In addition to comparing the Preferred Portfolio to the other portfolios under a variety of pricing assumptions, the Preferred Portfolio, New Carbon Free portfolio, Fleet Modification and Fleet Modification Prime portfolios, 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 Portfolio 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 four 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. Figure 31 shows the input variables or risk factors within this IRP stochastic analysis and the historical correlative relationships to each other. The range of values associated with the variable inputs is shown in Figure 32.

	Coal	Gas	Power	CO2
Coal	1	0.18	0.53	-0.98
Gas		1	0.47	0.96
Power			1	0.95
CO2				1
Standard Deviation	6.4%	19%	14.7%	43%

Figure 31. Risk Analysis Factors and Relationships

Comparing the Preferred Portfolio to portfolios which exclude one or both Rockport units provides us with a range of resource profiles, and therefore different revenue requirements, than those in the Preferred Portfolio.

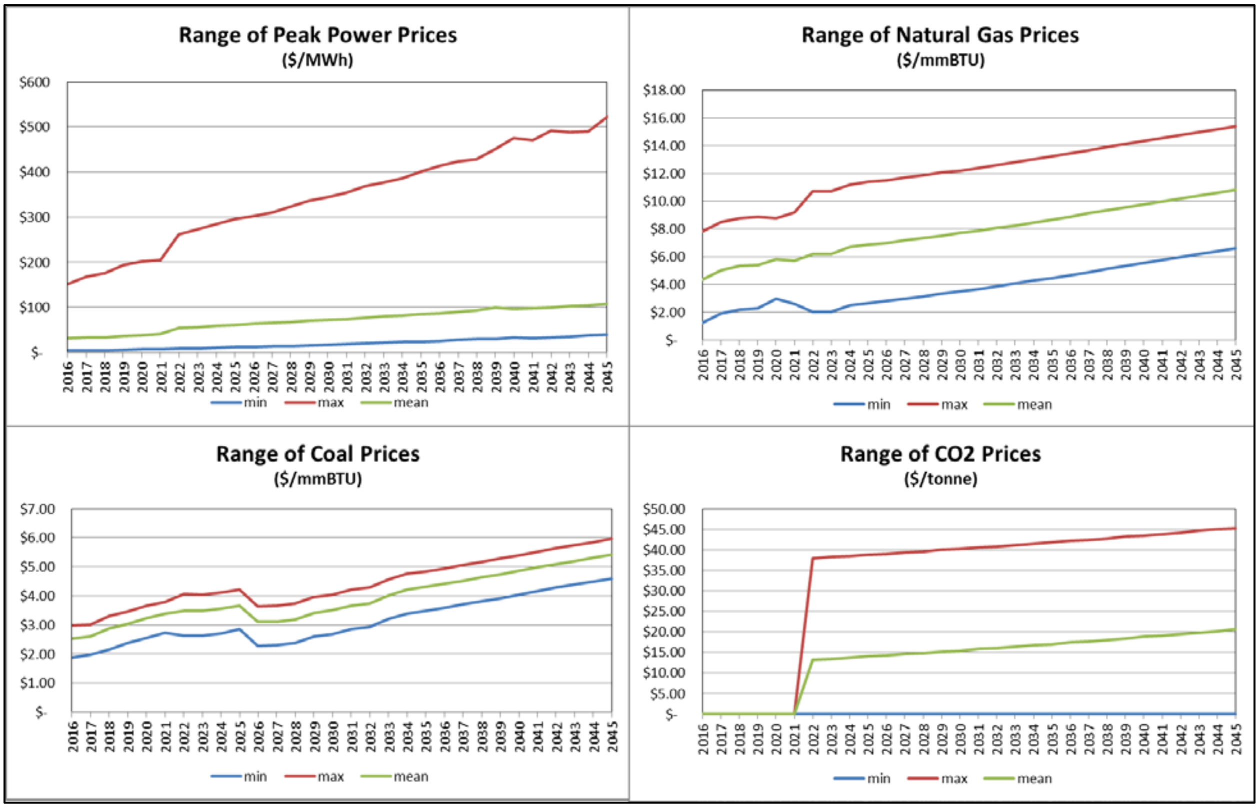

Figure 32. Range of Variable Inputs for Stochastic Analysis

5.3.1 Stochastic Modeling Process and Results

For each portfolio, the differential between the median and 95th percentile result from the multiple runs was identified as Revenue Requirement at Risk (RRaR). 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% 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 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 a levelized monthly bill impact) and the expected value graphically displayed.

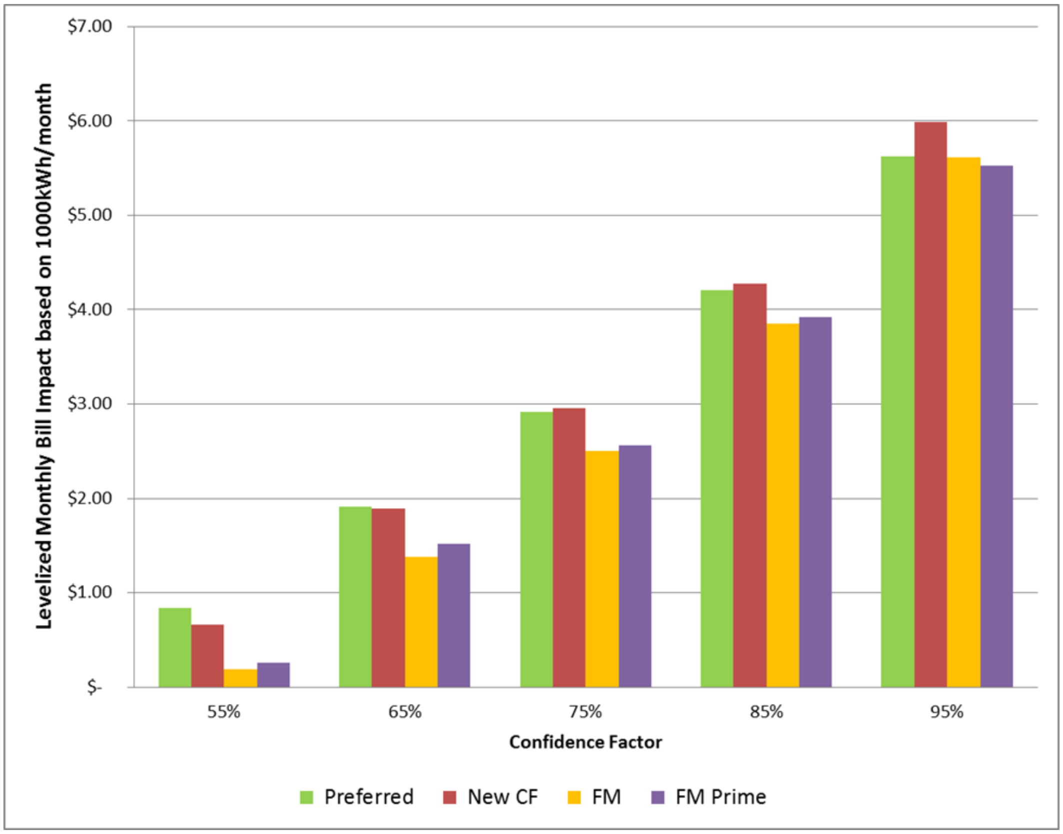

Figure 33. Revenue Requirement at Risk (RRaR) by Confidence Factor

The difference in RRaR between the portfolios is relatively small. The addition of NGCC plants, which have greater load following capability but operate at lower capacity factors than coal plants, works to slightly reduce the risk or revenue requirement volatility in the Fleet Modification and Fleet Modification Prime Portfolios, while the New Carbon Free portfolio, which places greater significance on PJM energy prices, is somewhat, but not exceptionally, more risky.

Based on the risk modeling performed, it is reasonable to conclude that the inherent risk characteristics of all the portfolios are comparable and that no one portfolio is significantly advantaged. This indicates that the Preferred Portfolio represents a reasonable combination of expected costs and risk relative to the cost-risk profile of the portfolios that exclude one or both Rockport units.

6.0 Conclusions and Recommendations

6.1 Plan Summary

The optimization results of this IRP demonstrate that I&M, as a stand-alone entity in the PJM RTO, can serve customer needs over the planning period with additional base-load combined-cycle generation, wind and solar renewables, CHP, and DSM resources, such as EE . The following are summary highlights of the Preferred Portfolio:

I&M's Preferred Portfolio

- Maintains I&M's two units at Rockport Plant, including the addition of Selective Catalytic Reduction (SCR) systems in 2017 and 2019; as well as FGD systems in 2025 and 2028
- Continues operation of I&M's carbon free nuclear plant through, minimally, its current license extension period
- Add 600MW (nameplate) of large-scale solar resources
- Add 1,350MW (nameplate) of wind resources
- Adds 1,253MW of Natural Gas Combined Cycle generation in 2035
- Implements end-use energy efficiency programs so as to reduce energy requirements by 914 GWh and capacity requirements by 70MW in 2035
- Adds 27MW of natural gas CHP generation
- Recognizes additional distributed solar capacity will be added by I&M's customers, starting in 2016, and ramping up to 5MW (nameplate) by 2035

Specific I&M capacity and energy production changes over the 20-year planning period associated with the Preferred Portfolio are shown in Figure 34 through Figure 37, below.

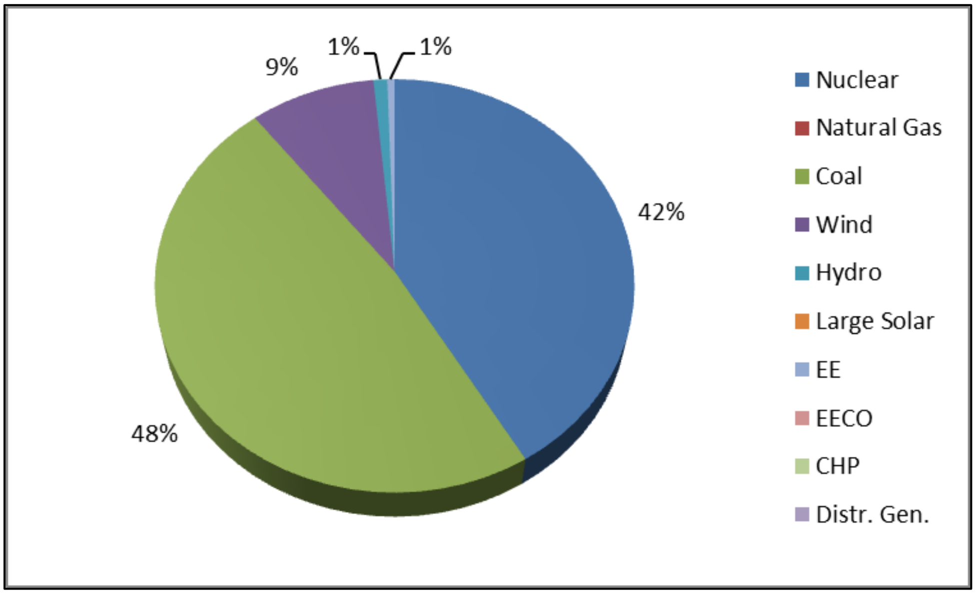

Figure 34. 2016 I&M Nameplate Capacity Mix

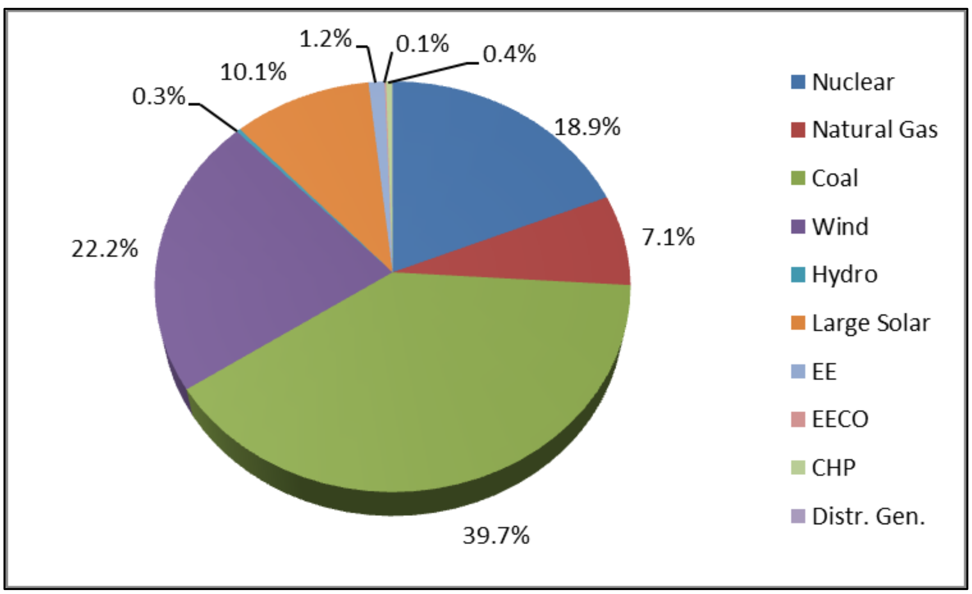

Figure 35. 2035 I&M Nameplate Capacity Mix

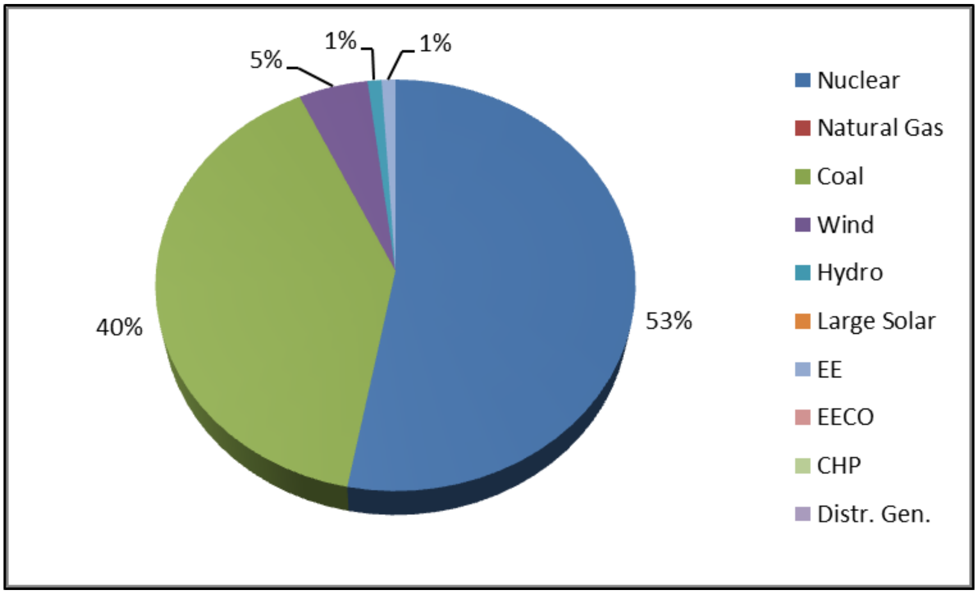

Figure 36. 2016 I&M Energy Mix

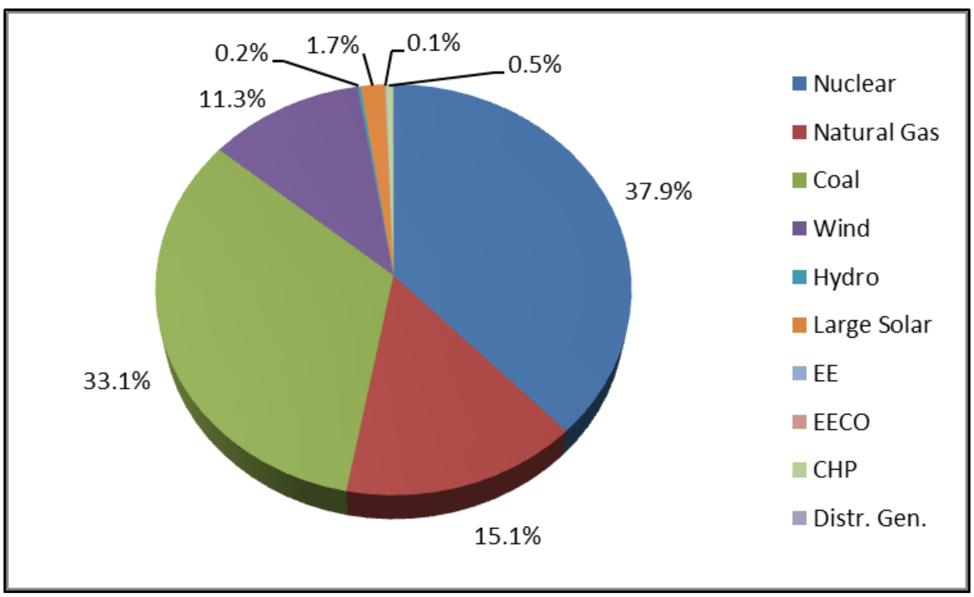

Figure 37. 2035 I&M Energy Mix

Figure 34 and Figure 35 indicate that this Preferred Portfolio would reduce I&M's reliance on coal and nuclear-based generation as part of its portfolio of resources, and increase reliance on renewable resources, thereby enhancing fuel diversity. Specifically, over the 20-year planning horizon the Company's capacity mix attributable to coal-based assets would decline from 48% to 40%; while nuclear assets would be anticipated to decline from 42% to 19% (under the assumption that one of the Cook Plant units would be retired at the end of its current license extension in 2034). To offset these reductions, in addition to new NGCC resources (7%), renewables (wind, solar, and hydro-- based on nameplate ratings) would be anticipated to increase from 10% to 33%, and, similarly, demand-side and energy-efficiency measures increase from 1% to 2% over the planning period. Figure 36 and Figure 37 show I&M's energy output attributable to coal-fueled assets decreases from 40% to 33%; while nuclear generation shows a decrease from 53% to 38% over the period. Likewise, in addition to energy from new NGCC generation(15%), renewable energy would be anticipated to increase from 6% to 13% over the planning period.

Figure 38 illustrates I&M's annual capacity position that incorporates the Preferred Portfolio, with respect to the Company's load obligation factoring in PJM's capacity margin requirement. Due to its intermittent nature, as well as the emerging PJM Capacity Performance reliability construct, the ultimate *capacit*y contribution from renewable resources is assumed to be fairly modest. However, such renewable resources can contribute a significant volume of *energy* resources. I&M's *Plexos*® optimization modeling selected these wind and solar resources because they were projected to add more relative value (*i.e.*, lowered I&M's net energy cost) than alternative resources examined, including the purchase of energy from the PJM market.

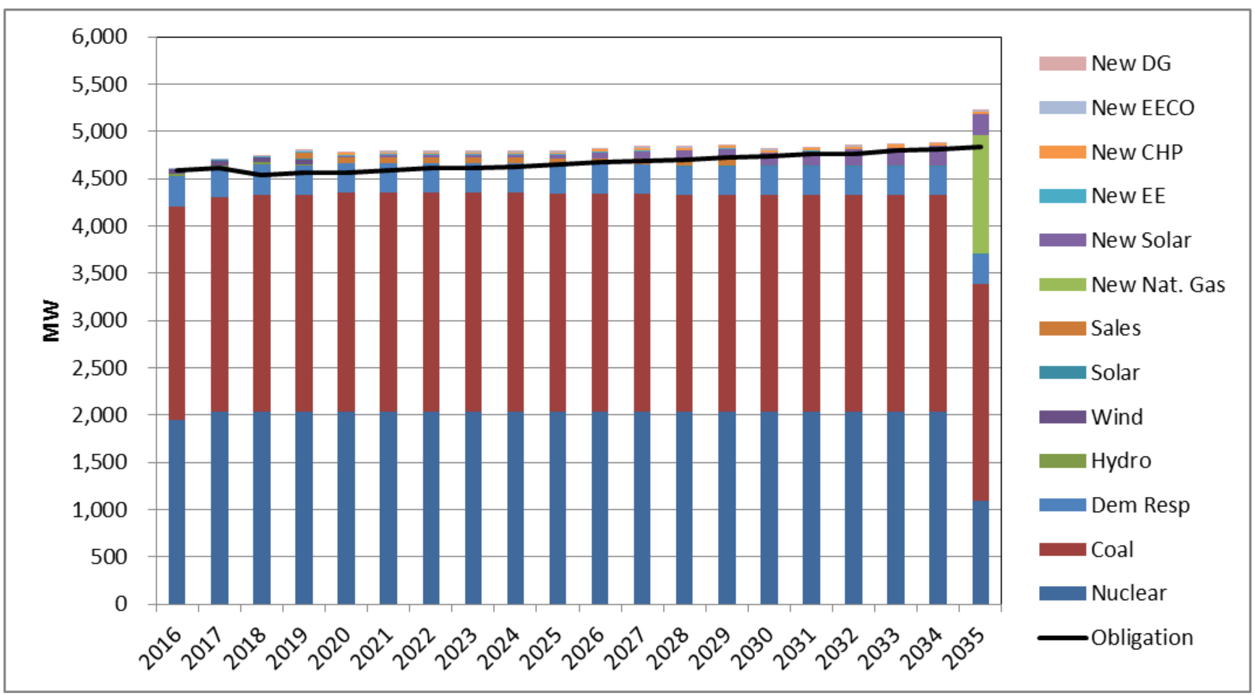

Figure 38. I&M Preferred Portfolio PJM Capacity Position throughout Planning Period (2016-2035)

Table 23 provides a summary of the Preferred Portfolio's PJM and nameplate capacity additions.

Table 23. Preferred Portfolio Cumulative Capacity Additions throughout Planning Period (2016-2035)

Indiana Michigan Power Company
2015 Integrated Resource Plan
Cumulative Resource Changes
Preferred Portfolio

MW		(1) (Cumulative) Existing Fleet	(2) (Cumulative) Firm Capacity Resource ADDITIONS: New-Build		(4)	(6) Energy Efficiency (EE)	(7)	(8)	(9) EECO	(10) DR	(11) Wind[D]	(12) Solar[E]	(13)	(14)=(1)to(13), ex(6, 10)	(15) Resulting I&M Reserves Above	(16)	(17) (Cumulative) 'NAMEPLATE' ADDITIONS: Wind[D]	(18) Solar[E]	(19)
IRP Period	PJM Planning Year[A]	Unit Uprates, Derates, and PJM Capacity Performance Impact	NG CTs	NG Combined Heat and Power	NGCC	'Embedded' Federal EE Regulations (Non-DSM EE) [B]	Current DSM Programs[C]	New	New	Pre-Existing DR Programs[C]		Utility Scale	Distributed	(Cumul.) NET 'RESOURCE' CHANGE[F]	PJM Minimum Rqrmnt[G]	PJM Reserve Margin %	No (PJM) capacity value assumed	Utility Scale	Distributed
Yr.		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW		MW	MW	MW
1	2016	-	-	-	-	206	26	-	6	298	No PJM Capacity value - see nameplate additions column	-	-	33	13	0.3%	-	-	-
2	2017	98 [F]	-	-	-	206	37	-	6	298		-	-	141	82	2.1%	-	-	-
3	2018	129 [G]	-	-	-	205	37	8	6	298		-	0.4	181	196	5.0%	-	-	1.0
4	2019	197 [H]	-	-	-	204	37	16	6	298		-	0.4	257	239	6.1%	-	-	1.0
5	2020	151 [I]	-	14	-	206	37	18	6	298		8	0.4	234	214	5.5%	150	20	1.0
6	2021	151	-	14	-	211	37	19	6	298		19	0.4	247	195	4.9%	150	50	1.0
7	2022	151	-	14	-	218	37	21	6	298		19	0.4	248	177	4.5%	150	50	1.0
8	2023	151	-	14	-	226	37	23	6	298		19	0.8	250	163	4.1%	150	50	2.0
9	2024	151	-	14	-	234	37	23	6	298		19	0.8	251	157	3.9%	300	50	2.0
10	2025	137 [J]	-	14	-	243	37	25	6	298		38	0.8	258	132	3.3%	450	100	2.0
11	2026	137	-	27	-	252	37	27	6	298		57	0.8	292	144	3.6%	600	150	2.0
12	2027	137	-	27	-	260	37	28	6	298		76	1.1	313	142	3.5%	750	200	3.0
13	2028	122 [K]	-	27	-	268	37	30	6	298		95	1.1	319	134	3.3%	900	250	3.0
14	2029	123	-	27	-	277	37	32	6	298		114	1.1	340	130	3.2%	1,050	300	3.0
15	2030	61 [L]	-	27	-	288	37	32	6	298		133	1.1	298	69	1.7%	1,200	350	3.0
16	2031	61	-	27	-	299	37	32	6	298		152	1.5	318	71	1.7%	1,350	400	4.0
17	2032	59	-	27	-	309	37	33	6	298		171	1.5	335	81	2.0%	1,350	450	4.0
18	2033	59	-	27	-	319	37	33	6	298		190	1.5	354	67	1.6%	1,350	500	4.0
19	2034	59	-	27	-	328	37	33	6	298		209	1.9	374	71	1.7%	1,350	550	5.0
20	2035	(872) [M]	-	27	1,253	399	37	34	6	298	-	228	1.9	715	391	9.4%	1,350	600	5.0
						328	70											605	
						'TOTAL' Energy Efficiency (2016-2035)												'TOTAL' Solar (2016-2035)	

[A] PJM Planning Year is effective 6/1/XXXX.
[B] Represents estimated energy efficiency levels already 'embedded' into I&M's long-term load & peak demand forecast based on emergence of PRIOR-ESTABLISHED Federal efficiency standareds (EPAct 2005; 2007 EISA, 2009 ARRA).
[C] Represents estimated contribution from current/known I&M DSM-EE and Demand Response (Interruptible, DLC/ELM) program activity also reflected in the Company's long-term load and demand forecast *(from CLR input sheet)*.
[D] Due to the intermittency of wind resources, I&M assumes 0% of nameplate' MW rating are included for capacity resource determination purposes beyond 2020.
[E] Due to the intermittency of solar resources, Utility and Distributed Solar receive 38% of nameplate MW rating for capacity resource determination purposes.

Changes to existing resources Post-June 1, 2015:
[F] Cook Unit 2 turbine Upgrade and rating adjustment
[G] Rockport 1 turbine upgrade.
[H] PJM EE nomination begins.
[I] Rockport 2 turbine upgrade offset by removal of wind/hydro for PJM CP.
[J] Rockport 1 FGD derate
[K] Rockport 2 FGD derate
[L] PJM EE Nomination ends
[M] Cook 1 Retires

[F] Includes changes in existing resources plus plan additions, excluding "embedded" EE and existing DR programs..
[G] PJM minimum criterion @15.7% as a function of peak demand.

6.1.1 I&M Short-Term Action Plan

I&M's Short-Term Action Plan applies to the period beginning November 2015 and ending December 2018. 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.

Steps to be taken by I&M in the near future to implement this plan include:

1. Continue the planning and regulatory actions necessary to manage and implement economic energy efficiency programs in Indiana and Michigan. This primarily consists of efficient administration and implementation, managing performance, reporting and evaluating current programs, and assessing market conditions through a forward-looking market potential study for the Company.
2. Continue to evaluate the Final EPA CPP guidelines and provide technical input to state regulatory bodies regarding cost effective compliance options based on on-going activity.

In addition to the steps pertaining to the short-term action plan, I&M will continue to implement plans associated with the following:

- Cook Plant's Life-Cycle Management (LCM) program
- Engineering, design and construction associated with the Rockport Unit 1 SCR, to be completed and in-service in 2017
- Completing construction and commissioning of the pilot solar project.

The Short-Term Action Plan will require I&M to make investments to accomplish Item 1 shown above, the estimated expenditures for 2016 and 2017 are in the range of $20 million per year with coincident capacity savings of approximately 12MW in 2016 and 10MW[17] in 2017 and energy savings of 175GWh per year. For 2018, the Preferred Portfolio suggests investments of approximately $23 million with an estimated coincident capacity savings of 8MW and energy

[17] The estimated capacity savings in 2016 and 2017 is based on coincident peak impacts with the system load. The estimated capacity savings within the filed plans are based on DSM load shapes and are 37MW in 2016 and while there is not a filed plan in Indiana for 2017, I&M would expect similar capacity savings if funding levels are approved.

savings of 175GWh. At this time, I&M does not have an estimate to evaluate the Final CPP guidelines.

I&M accomplishments related to the 2013 IRP Short Term Action Plan include the following items that have been either completed or are on schedule for completion:

- Acquired 200MW of Wind resources through the Headwaters project;
- Initiated and received approval to build a 14.7MW Solar Pilot Program, which will allow I&M to improve the overall understanding and integration of solar technology as a system resource;
- A DSI system has been installed at the Rockport Plant to meet the HCl limit under the MATS Rule;
- As of June 2015, completed 37 Cook Plant LCM related activities
- Continued to implement demand-side management programs, began a transition to utility administered programs based on I&M demographic attributes and characteristics, and introduced two new programs including I&M's Electric Energy Consumption Optimization program
- Tanners Creek units 1-4 have been removed from service

6.2 Conclusion

This IRP provides for reliable electric utility service, at reasonable cost, through a combination of renewable supply-side resources and demand-side programs and serves as a roadmap for I&M to provide adequate capacity resources to serve its customers' peak demand and required PJM reserve margin needs throughout the forecast period.

The highlighted Preferred Portfolio offers incremental resources that will provide—in addition to the needed PJM installed capacity to achieve mandatory PJM (summer) peak demand requirements—additional carbon-free energy so as to protect the Company's customers from being overly exposed to PJM energy markets that could be influenced by many external factors, including the impact of carbon, going-forward.

The IRP process is a continuous activity; assumptions and plans are continually reviewed as new information becomes available and modified as appropriate. Indeed, the capacity and energy resource plan reported herein reflects, to a large extent, assumptions that are subject to change; it is simply a snapshot of the future at this time. This IRP is not a commitment to a specific course of action, as the future is highly uncertain. The resource planning process is becoming increasingly complex when considering pending regulatory restrictions, technology advancement, changing energy supply pricing fundamentals, uncertainty of demand and EE advancements. These complexities necessitate the need for flexibility and adaptability in any ongoing planning activity and resource planning processes. Lastly, the ability to invest in capital-intensive generation infrastructure is increasingly challenged in light of current economic conditions and the impact of all these factors on I&M's customers are a primary consideration in this report.

Appendix

Exhibit	Description
A	Load Forecast Tables
B	Short Term Large Industrial Energy Models
C	Long Term Industrial and Wholesale Model Data
D	Model Equations and Statistical Test Results
E	Stakeholder Responses
F	Case and Scenario Results
G	New Generation Resources
H	FERC Form 715
I	AEP East Transmission Map
J	Projected Fuel Costs
K	I&M Internal Hourly Load Data
L	IRP Public Summary Document
M	IRP Cross-Reference Table