AEP
INDIANA MICHIGAN POWER®
A unit of American Electric Power

Indiana Michigan Power
P O Box 60
Fort Wayne, IN 46801
www.IndianaMichiganPower.com

Ms. Kavita Kale
Executive Secretary
Michigan Public Service Commission
P. O. Box 30221
Lansing, Michigan 48909

September 30, 2016

Dear Ms. Kale:

Re: Case No. U-18144

Attached for filing through the MPSC's Electronic Case Filings system is Indiana Michigan Power Company's (I&M) 2017 Power Supply Cost Recovery Plan Case, Case No. U-18144, along with a proposed Notice of Hearing.

Thank you for your attention to this matter. If you have any questions or comments, please contact me.

Sincerely,

Andrew J. Williamson

Digitally signed by Andrew J. Williamson
DN: cn=Andrew J. Williamson, o=Indiana Michigan Power Company, ou=Director of Regulatory Services, email=ajwilliamson@aep.com, c=US
Date: 2016.09.30 11:16:25 -04'00'

Andrew J. Williamson
Director of Regulatory Services

Attachment

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION
NOTICE OF HEARING
FOR THE MICHIGAN CUSTOMERS OF
INDIANA MICHIGAN POWER COMPANY
CASE NO. U-18144

- Indiana Michigan Power Company requests Michigan Public Service Commission approval to implement a power supply cost recovery (PSCR) plan and a PSCR factor of 10.50 mills per kilowatt-hour (kWh) or $0.01050 per kWh to compute its Michigan electric customers' bills for the billing months of January 2017 through December 2017.

- The information below describes how a person may participate in this case.

- You may contact Indiana Michigan Power Company, 2425 Meadowbrook Road, Benton Harbor, Michigan 49023, (800) 311-6424, for a free copy of its application. Any person may review the application at the offices of Indiana Michigan Power Company.

- The first public hearing in this matter will be held:

DATE/TIME:	**Tuesday, November 29, 2016, at 10:00 a.m.** This hearing will be a prehearing conference to set future hearing dates and decide other procedural matters.
BEFORE:	Administrative Law Judge
LOCATION:	Michigan Public Service Commission 7109 West Saginaw Highway Lansing, Michigan
PARTICIPATION:	Any interested person may attend and participate. The hearing site is accessible, including handicapped parking. Persons needing any accommodation to participate should contact the Commission's Executive Secretary at (517) 284-8090 in advance to request mobility, visual, hearing or other assistance.

The Michigan Public Service Commission (Commission) will hold a hearing to consider Indiana Michigan Power Company's (I&M) September 30, 2016 application to implement a PSCR plan and PSCR factor of 10.50 mills per kilowatt-hour (kWh) or $0.01050 per kWh to compute it's Michigan electric customers' bills for the billing months of January 2017 through December 2017.

All documents filed in this case shall be submitted electronically through the Commission's E-Dockets website at: michigan.gov/mpscedockets. Requirements and instructions for filing can be found in the User Manual on the E-Dockets help page. Documents may also be submitted, in Word or PDF format, as an attachment to an email sent to: mpscedockets@michigan.gov. If you require assistance prior to e-filing, contact Commission staff at (517) 284-8090 or by email at: mpscedockets@michigan.gov.

Any person wishing to intervene and become a party to the case shall electronically file a petition to intervene with this Commission by November 22, 2016. (Interested persons may elect to file using the traditional paper format.) The proof of service shall indicate service upon I&M's attorney, Richard J. Aaron, Dykema Gossett PLLC, Capitol View, 201 Townsend Street, Suite 900, Lansing, Michigan 48933.

Any person wishing to appear at the hearing to make a statement of position without becoming a party to the case may participate by filing an appearance. To file an appearance, the individual must attend the hearing and advise the presiding administrative law judge of his or her wish to make a statement of position. All information submitted to the Commission in this matter becomes public information, thus available on the Michigan Public Service Commission's website, and subject to disclosure. Please do not include information you wish to remain private.

Requests for adjournment must be made pursuant to the Michigan Administrative Hearing System's Administrative Hearing Rules R 792.10422 and R 792.10432. Requests for further information on adjournment should be directed to (517) 284-8130.

A copy of I&M's request may be reviewed on the Commission's website at: michigan.gov/mpscedockets, and at the office of Indiana Michigan Power Company. For more information on how to participate in a case, you may contact the Commission at the above address or by telephone at (517) 284-8090.

The Utility Consumer Representation Fund has been created for the purpose of aiding in the representation of residential utility customers in 1982 P.A. 304 proceedings. Contact the Chairperson, Utility Consumer Participation Board, Department of Licensing and Regulatory Affairs, P.O. Box 30004, Lansing, Michigan 48909, for more information.

Jurisdiction is pursuant to 1909 PA 106, as amended, MCL 460.551 et seq.; 1919 PA 419, as amended, MCL 460.54 et seq.; 1939 PA 3, as amended, MCL 460.1 et seq.; 1969 PA 306, as amended, MCL 24.201 et seq.; 1982 PA 304, as amended, MCL 460.6j et seq.; and the Michigan Administrative Hearing System's Administrative Hearing Rules, 2015 AC, R 792.10401 et seq.

INDIANA MICHIGAN POWER COMPANY

2017 POWER SUPPLY COST RECOVERY PLAN CASE

MPSC CASE NO. U-18144

FILED: SEPTEMBER 30, 2016

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of INDIANA MICHIGAN POWER COMPANY for approval of a Power Supply Cost Recovery Plan and factors (2017)	)))))	Case No. U-18144

APPLICATION

Indiana Michigan Power Company (I&M), in accordance with 1982 PA 304 (Act 304), submits this Application requesting approval of its proposed 2017 Power Supply Cost Recovery (PSCR) Plan and proposed factors. In support of this Application, I&M respectfully represents to the Michigan Public Service Commission (MPSC or Commission) as follows:

1. I&M is a corporation organized and existing under the laws of the State of Indiana and is authorized to do business in the State of Michigan. I&M's principal offices and place of business are located in the City of Fort Wayne, Indiana. I&M has corporate power and authority, among other things, to engage in generating, transmitting, distributing, and selling electric energy within the State of Michigan and within the State of Indiana.

2. The electric system of I&M is a completely integrated and interconnected entity and is operated as a single utility. I&M's service area is located in southwestern Michigan and northern and eastern Indiana. I&M provides electric service to approximately 128,000 retail electric customers in the State of Michigan. I&M's service area in Michigan consists of customers in the counties of Allegan, Berrien, Cass, Kalamazoo, St. Joseph, and Van Buren.

3. I&M is a wholly-owned subsidiary of the American Electric Power Company, Inc., and is operated as a single utility in the American Electric Power System (AEP System). The operating subsidiaries of the AEP System, including I&M, are interconnected and operate under arrangements that provide for securing increased economies through coordination planning, and operations.

4. I&M's retail electric business in the State of Michigan is subject to the jurisdiction of the Commission pursuant to 1909 PA 106, as amended, MCL 460.551 et seq.; 1909 PA 300, as amended, MCL 462.2 et seq.; 1919 PA 419, as amended, MCL 460.51 et seq.; 1939 PA 3, as amended, including the amendments set forth in Act 304, MCL 460.1 et seq.

5. On September 27, 1983, the Commission approved I&M's requested PSCR Clause, with certain modifications, and rescinded I&M's previously approved fuel and purchased and interchanged power clauses. By its Order in Case No. U-9912, the Commission modified I&M's PSCR Clause to reflect separate PSCR factors for the St. Joseph and Three Rivers Rate Areas. By its Order in Case No. U-16180, the Commission modified I&M's PSCR Clause to reflect a single rate area with a unified PSCR Clause.

6. I&M's current PSCR Clause provides for the recovery through rates of the cost of power supply incurred to serve I&M's customers in the State of Michigan. I&M's approved PSCR Clause provides for 23.77 mills per kilowatt-hour (kWh), including losses, of such costs to be recovered through base rates, with any increases or decreases from the base cost to be recovered through a PSCR factor.

7. To implement a PSCR Clause in its rates and rate schedules, I&M is required to file a PSCR Plan.

8. In addition to the requirements for the PSCR Plan in Paragraph 7 above, I&M is required to file a five-year forecast of the power supply requirements of its customers, its anticipated sources of supply, and projections of power supply costs.

9. I&M also requests continuation of the roll-in methodology approved in MPSC Case No. U-15004, I&M's 2007 PSCR Plan, which provides better rate stability, improves bill clarity, minimizes customer confusion and uncertainty, and is administratively more efficient and cost effective. I&M represents that in addition to I&M this similar methodology has been approved by the Commission in connection with other companies PSCR and Gas Cost Recovery (GCR) clauses.

10. In accordance with the requirements of Act 304 and for the implementation of a PSCR Clause, I&M files this Application for approval of a PSCR Plan and for approval to apply its proposed PSCR factors to customers in the State of Michigan. As shown on Exhibit A, I&M requests authority to apply a PSCR factor of 10.50 mills per kWh to customers' bills for each of the billing months of January 2017 through December 2017. The proposed PSCR factor represents an increase of 1.61 mills per kWh from the current PSCR factor.

11. I&M is filing with this Application its testimony and exhibits detailing its PSCR Plan as required by Act 304 and supporting its requested PSCR factor. The filed testimony and exhibits also contain I&M's five-year forecast of the power supply requirements of its customers, its anticipated sources of supply, and projections of power supply costs in light of its existing sources of electrical generation and sources of electrical generation under construction.

WHEREFORE, I&M respectfully requests that the Commission:

1. Accept for filing this Application for approval of a PSCR Plan and

PSCR factors.

2. Upon acceptance of the filing of this Application, fix a time and place for hearing and give notice thereof in accordance with the law and rules of practice established by this Commission.

3. Promptly make such investigation as it may deem necessary or advisable in the circumstances.

4. Authorize I&M to continue the roll-in methodology in connection with its PSCR clause.

5. Promptly enter its Order approving I&M's 2017 PSCR Plan as reasonable and prudent and a PSCR factor of 10.50 mills per kWh for each of the billing months of January 2017 through December 2017

6. Grant I&M such other additional relief as it may deem appropriate.

Respectfully submitted,

INDIANA MICHIGAN POWER COMPANY

By Andrew J. Williamson

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Date: 2016.09.30 11:17:20 -04'00'

Andrew J. Williamson
Director of Regulatory Services

Richard J. Aaron (P35605)
Dykema Gossett PLLC
Capital View
201 Townsend Street, Suite 900
Lansing, Michigan 48933
(517) 374-9198
RAaron@dykema.com

Attorneys for Indiana Michigan Power Company

<u>VERIFICATION</u>

STATE OF INDIANA)
) SS
COUNTY OF ALLEN)

Andrew J. Williamson being first duly sworn, deposes and says that he is Director of Regulatory Services of Indiana Michigan Power Company, an Indiana corporation; that he is duly authorized to and has executed the foregoing Application for and on behalf of Indiana Michigan Power Company; that he has read the same and knows the contents thereof, and that the same is true to the best of his knowledge, information, and belief.

Andrew J. Williamson

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Date: 2016.09.30 11:17:41 -04'00'

Andrew J. Williamson

Subscribed and sworn to before me
this 30th day of September, 2016.

Regiana M. Sistevaris

Digitally signed by Regiana M. Sistevaris
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Regiana Maria Sistevaris
Notary Public, State of Indiana
County of Allen
My Commission Expires January 7, 2023

Indiana Michigan Power Company
Determination of the Michigan Jurisdiction
Power Supply Cost Recovery Factor
January 2017 - December 2017

Line No.	Description	Twelve Month Totals	
1	Total Power Supply Costs (000's)	$469,647	
2	Net Energy Requirement (GWh)	24,235	
3	Line 1 / Line 2	19.37	Mills/kWh
4	Line 3 * 1.046	20.26	Mills/kWh
5	Plus: PSCR Transmission Factor (See Exhibit DLH-2)	10.70	Mills/kWh
6	Less Current Power Supply Cost Base	23.77	Mills/kWh
7	Subtotal - Line 4 plus Line 5 less Line 6	7.19	Mills/kWh
8	Estimated 2016 Under-recovery of $9,242,535/ 2,789,000,000 Est'd kWh 2017	3.31	Mills/kWh
9	PSCR Billing Factor for the Michigan Jurisdiction - Line 7 + Line 8	10.50	Mills/kWh

DIRECT TESTIMONY OF HAZEL A. BAKER
ON BEHALF OF
INDIANA MICHIGAN POWER COMPANY
2017 PSCR PLAN CASE

A. Introduction

Q. Please state your name, business address, and present position.

A. My name is Hazel A. Baker. My business address is 1 Riverside Plaza, Columbus, Ohio, 43215. I am Resource Planning Analyst Staff - Resource Planning in the Corporate Planning & Budgeting Department of the American Electric Power Service Corporation, a wholly owned subsidiary of the American Electric Power Company, Inc. (AEP), the parent company of Indiana Michigan Power Company (I&M).

Q. Please briefly describe your educational and professional background.

A. I received an Associate of Applied Business degree in Computer Programming, with honors, from Central Ohio Technical College in 1984 and a Bachelor of Science degree in Computer Management, *summa cum laude*, from Franklin University in 1991. In 1985, I joined AEP's System Planning Department as an Engineering Technician, and progressed to my current position in 2015.

Q. Please briefly describe the responsibilities of the Resource Planning Section.

A. The Resource Planning Section is a part of the Corporate Planning and Budgeting Department, as is the Economic Forecasting Section, which carries out load forecasts for the System and its operating companies. The Resource Planning Section is responsible for analyses and evaluations of the AEP

System's load and capacity relationships, to determine the size, type, fuel, and timing of new supply-side resources (facilities or power purchases, or both), as well as for participation in evaluations regarding demand-side management (DSM) programs, as part of AEP's Integrated Resource Planning (IRP) process. It also develops generation and production cost forecasts for the AEP System for internal and external (regulatory) use, and carries out many other activities in areas related to resource planning.

Q. Please briefly outline your duties in the Resource Planning Section.

A. My responsibilities include developing the power systems modeling of AEP's energy assets, (e.g. coal, gas and nuclear power plants, renewable energy) energy contracts, and market transactions. This modeling supports the Strategic and Financial Planning of the company by providing production cost forecasts to internal stakeholders such as the Financial Forecasting group and various company officials. In addition, I construct production cost forecasts which are utilized to support regulatory filings throughout our jurisdictions in the AEP-East service territory. I also perform ad-hoc sensitivity analyses and economic studies relating to the operation of our energy assets and contracts.

In performing my duties, I am familiar with the preparation and content of I&M's load forecast.

Q. Have you previously submitted testimony or testified in any proceeding?

A. Yes, in 2005, I testified in the New Source Review (NSR) trial at the U.S. District Court for the Southern District of Ohio.

Q. What is the purpose of your testimony in this proceeding?

A. My testimony supports I&M's expected electric power demand and energy requirements and anticipated sources of power supply on a monthly basis for 2017 as well as on an annual basis for the five-year forecast period (2017-2021). I describe the major contracts and power supply arrangements entered into by I&M for providing power supply. I describe I&M's integrated resource planning process (IRP), and will also testify as to the reasonableness and prudence of I&M's decisions to provide power supply in the manner described. In addition, I present testimony with respect to the reasonableness of I&M's reserve levels.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring exhibits IM-1 (HAB-1) through IM-9 (HAB-9).

Q. Were these exhibits prepared by you or under your direction and supervision?

A. Yes.

B. Load Forecast

Q. Has a forecast been made of the load requirements of I&M's customers?

A. Yes. Exhibit IM-1 (HAB-1) shows actual and forecast I&M seasonal peak internal demands, energy requirements and load factors for the years 2006 through 2021 along with annual and average rates of growth in demand and energy for the historical and forecast periods. Similarly, Exhibit IM-2 (HAB-2) presents the annual energy requirements for the residential, commercial and industrial sectors, other internal requirements, and the total internal energy requirements for I&M.

Q. What were the procedures used in making the I&M forecast?

A. Two distinct methods were used for forecasting energy. First, regression models with time series error terms were used to forecast energy sales up to 18 months ahead (short-term). These models use the most recent customer count, kWh sales data, weather data (in the form of degree days), and indicator (dummy) variables where needed.

The second method is the long-term process that starts with economic forecasts provided by Moody's Analytics for the United States as a whole, each state, and counties within each state. These include regional forecasts of such variables as employment, population, and income, as well as national forecasts of industrial production indices and producer and consumer price indices. The long-term energy forecast uses econometric models incorporating the economic forecast to produce a forecast of kWh sales. In the residential and commercial classes the models are end-use based econometric models, called Statistically Adjusted End-Use models, developed by Itron, Inc. Inputs such as regional and national economic and demographic conditions, energy prices, weather data, and customer-specific information are all utilized in producing the forecasts.

To forecast peak demand, MetrixND (load forecasting software developed by Itron, Inc) was used. The initial phase is to develop representative load shapes for each retail revenue class by using regression and neural network models. Inputs include historical load research data, weather, and calendar variables. Then, these shapes are combined with the sales forecast to produce aggregated load shapes for each jurisdiction. This is done using software products developed by SAS, Inc. Load factors are derived and then corresponding hourly load shapes are calibrated, resulting in final seasonal and monthly peaks. Separate models are used for each FERC customer using a similar approach.

Q. How is Energy Efficiency and Demand Response (EE/DR) included in the forecast?

A. The impacts of any long-standing existing EE/DR programs for each jurisdiction are embedded in the historical data that are supplied to the trend and econometric load-forecasting models. Thus, the models already account for these programs. Additionally, any new legislative or commission-approved EE/DR programs, such as the energy optimization programs specified in 2008 PA 295, are explicitly accounted for in the load forecast, as well as any additional proposed EE/DR programs. The aggregate EE/DR demand impacts for I&M are shown in Exhibit IM-7 (HAB-7).

C. Retail Competition

Q. Have you considered the impacts of Michigan electric industry restructuring and retail customer choice?

A. Yes, with regard to the impacts of Michigan electric industry restructuring and retail customer choice, i.e., Open Access Distribution (OAD), there are currently three alternative electric suppliers that have registered to compete for the Company's customers. Currently, participation in I&M's OAD is limited to 10 percent of I&M's 2015 weather-adjusted Michigan jurisdiction retail sales, or about 284 GWh. As of August 2016 I&M has no OAD customers. Accordingly, at this time, it is not appropriate to include any retail competition adjustments to the load forecast in this year's PSCR filing.

D. Other Load Commitments and System Sales

Q. In addition to I&M's internal load, what other loads are part of this forecast?

A. Whenever I&M has energy available beyond what is needed to supply its internal load together with any contractual commitments to non-associated power systems, this energy is offered to the PJM market.

Exhibit IM-3 (HAB-3) includes a month-by-month projection for 2017 of I&M's energy sales into the PJM market. Similarly, Exhibit IM-4 (HAB-4) includes an annual projection of such sales for the five-year forecast period 2017-2021. It is worth noting that the projected PJM market energy sales indicate that I&M is projected to have a net long energy position. In both exhibits, the other major components of I&M's load obligations are also included, to arrive at I&M's Total System Load.

E. Generating Capacity

Q. What is I&M's generating capacity to supply the peak internal demands

and energy requirements projected in Exhibits IM-1 (HAB-1) and IM-2 (HAB-2)?

A. Exhibit IM-5 (HAB-5) shows I&M's expected capacity resources for the 2017 summer peak.

Q. Does I&M have any committed capacity/energy purchase agreements?

A. Yes, Exhibit IM-5 (HAB-5) shows that I&M's committed capacity/energy purchase agreements totals to 217 MW (summer UCAP rating).

Q. Please describe I&M's special power supply arrangements related to the Rockport Plant.

A. As illustrated in Exhibit IM-6 (HAB-6), the Rockport Plant consists of two 1,300-MW (nominal) generating units which are jointly owned or leased by I&M and AEP Generating Company (AEG), another AEP subsidiary. I&M's projected generating capacity resources reflect the following Rockport-related arrangements:

1. I&M's 50% ownership share of Rockport Unit 1 and I&M's 50% leased share of Rockport Unit 2 (i.e., 660 MW of Unit 1 and 650 MW of Unit 2).
2. AEG's 50% share of Rockport Unit 1 and AEG's 50% leased share of Rockport Unit 2 (i.e., 660 MW of Unit 1 and 650 MW of Unit 2).
3. The Unit Power sale agreements among AEG, I&M, and Kentucky Power Company (KPCo), another AEP System operating company, under which I&M committed to purchase 70% of AEG's share of each Rockport unit, and KPCo

committed to purchase 30% of AEG's share of each Rockport unit.

The agreements by which KPCo purchases shares of the Rockport units are through December 7, 2022. I&M's net capacity resources for 2017 from Rockport Unit 1 include 1,122 MW (winter) and 1,118 (summer) and 1,105 MW (winter & summer) from Rockport Unit 2.

Q. Please describe the general terms of I&M's purchase of Rockport Units 1 and 2 capacity from AEG.

A. Under the terms of the Unit Power Agreement between I&M and AEG (FERC Rate Schedule No. 1), dated March 31, 1982, as amended, AEG makes available to I&M up to 70% MW of the power and associated energy from its share of Rockport Units 1 and 2. I&M, in turn, pays to AEG amounts sufficient to cover, among other things, AEG's operating and other expenses related to the amount of power sold to I&M.

Q. Are any capacity additions projected for I&M during the 2017 – 2021 forecast period?

A. No new capacity additions are under construction, or have been approved for construction, for I&M during the 2017 – 2021 forecast period. However, the forecast includes the addition of 150 MW of wind purchase beginning January 1, 2020, as well as, the addition of 20 MW and 30 MW of solar purchases beginning January 1, 2020 and January 1, 2021, respectively.

F. Reserve Margins

Q. What are I&M's projected reserve margins?

A. Assuming that I&M is viewed individually as part of a PJM planning perspective, Exhibit IM-7 (HAB-7) provides a projected PJM view of summer peak demands, capabilities, and margins for I&M for the 2017/18 PJM planning year through the 2021/22 planning year on an I&M “stand-alone” capacity position within PJM. This view is based on I&M continuing to participate, along with the other AEP East companies in the optional, FERC-authorized Fixed Resource Requirement (FRR) construct. FRR requires AEP and I&M to set forth its future capacity resource profile and position under, essentially, a “self-planning” format that is predicated upon ensuring the stand-alone achievement of its future customer peak demand plus PJM Installed Reserve Margin (IRM) requirements. That projection assumes that the underlying minimum reserve margin criteria to be utilized in the determination of I&M capacity needs are the IRM levels shown in Column 19. During the 2017/18 through 2021/22 period, as shown in Column 21, I&M’s projected margins are above the PJM IRM.

G. Environmental Issues

Q. Please summarize the relevant environmental regulations that affect I&M.

A. The following is a summary of the significant upcoming or recently finalized environmental regulations expected to impact I&M’s coal-fired power plant during the forecast period.

- The Cross State Air Pollution Rule (CSAPR), which established a cap and trade program to reduce emissions of NO_X and SO_2 in covered states including Indiana was finalized by the U.S. Environmental Protection Agency (EPA) in 2011 and, upon appeal, was overturned by the D. C. Circuit Court of Appeals in August 2012. EPA subsequently appealed this decision to the Supreme Court and on April 29, 2014, the Supreme Court issued its decision agreeing in part with EPA and remanding the case back to the DC Circuit Court for additional litigation proceedings. On October 23, 2014, the D.C. Circuit Court granted EPA's request to lift the CSAPR stay and delay the compliance deadlines by three years. Accordingly, CSAPR Phase 1 implementation took effect January 1, 2015. Phase 2 will begin in 2017. In December 2015, EPA proposed an update to the CSAPR rule to address the 2008 revised ozone national ambient air quality standard. This rule was finalized by EPA in September 2016 and imposes more stringent NOx budgets during ozone season for most states subject to this rule. Due to the timing of the issuance of the final rule, the impact, if any, has not been reflected in this forecast.
- The Mercury and Air Toxics Standard final rule was published in the federal register on February 16, 2012 and had a compliance deadline of April 16, 2015. This rule imposed stringent emissions limits, on a unit-by-unit basis, for mercury, acid gases and several other hazardous air

pollutants.

- On August 3, 2015 EPA issued its final Clean Power Plan rule. The rule focuses on cutting carbon pollution from the power sector by 870 million tons by 2030, a 32 percent decrease from 2005 levels. The final rule contains a carbon dioxide emission rate or tonnage goal for each state that would have to be achieved by 2030, along with interim goals starting in 2022. State plan submittals to EPA are required by September 2016. States requesting an extension, that meet certain criteria regarding plan development, will have until September 2018 to submit final plans. EPA has proposed a Federal Implementation Plan (FIP) that the agency indicated would be finalized in 2016 and would be imposed on those states that fail to submit an adequate state plan. In February 2016, the US Supreme Court stayed this rule, including all associated deadlines, until the legal challenge process has been completed. The DC Circuit Court is scheduled to hear oral arguments on this rule in September 2016.
- EPA promulgated a final rule under Section 316(b) of the Clean Water Act (CWA) in May of 2014. The rule prescribes technology standards for cooling water intake structures that would decrease impingement and entrainment of fish and other aquatic organisms. It is not expected to significantly impact I&M operations. Also under the CWA, in September of 2015, EPA finalized a rule updating the Effluent Limitation

Guidelines for the steam electric power generating category. This final rule requires compliance with technology-based limits for wastewater discharges from power plants with a main focus on process water and wastewater from FGD, fly ash sluice water, bottom ash sluice water and landfill/pond leachate.

- The final CCR Rule was published in the *Federal Register* on April 17, 2015 and had an effective date of October 14, 2015. The CCR Rule establishes, for coal-fired power plants, specific design and monitoring standards for new and existing landfills and surface impoundments, as well as measures to ensure and maintain the structural integrity of surface impoundments/ponds. The CCR Rule could lead to converting "wet" ash disposal systems to "dry" ash handling and disposal, the relining or closing of any ash ponds that exceed groundwater quality standards and other site-specific location criteria, and construction of additional wastewater treatment facilities. The Rockport Plant is already equipped with a dry fly ash handling system and a dry ash landfill to meet current permit requirements which positions the plant well concerning compliance with the final CCR Rule.
- On October 26, 2015, EPA published a final rule revising the 2008 Ozone NAAQS to a more stringent standard of 70 parts per billion. The final rule specifies that states must submit designations to EPA by October, 2016 and EPA must issue final designations by October 2017.

Attainment must be achieved starting early next decade for some areas and as late as 2037 for others depending on the severity of nonattainment status. I&M anticipates working with Indiana Department of Environmental Management as they develop compliance plans.

Q. Please summarize the modifications to the AEP NSR Consent Decree.

A. On December 10, 2007, the U.S. District Court for the Southern District of Ohio entered a final settlement agreement among I&M and other AEP companies, EPA, eight states and thirteen environmental organizations in connection with litigation regarding alleged violations of the NSR provisions of the Clean Air Act. The NSR litigation settlement includes requirements to complete the installation of additional controls at specific units in the eastern zone of the AEP System and to achieve sufficient reductions to comply with annual emission caps for NO_X and SO_2. In February 2013, the parties to the NSR Consent Decree requested a federal court to approve a modification to that agreement. This modification includes lower SO_2 emission caps for both the Rockport Plant and the AEP Eastern System plants. It also allows I&M to install lower-cost dry sorbent injection technology for SO_2 emission reduction at both units of Rockport Plant. As part of the agreement, I&M agreed to acquire an additional 200 MW of wind energy and retire or refuel Tanners Creek Unit 4. Tanners Creek Unit 4 was retired on May 31, 2015.

H. Integrated Resource Planning

Q. Please describe I&M's IRP process.

A. I&M's IRP process includes the following steps:

1) Identify the current issues as they relate to resource planning, such as the environmental issues described in Section G;

2) Forecast demand and energy, as described in Section B;

3) Identify demand-side options, as described in Section B;

4) Identify current resources and projected changes to those resources, as depicted in Exhibits IM-5 (HAB-5) and IM-7 (HAB-7);

5) Identify demand-side and supply-side resource options; and

6) Perform resource modeling, develop portfolios, and determine the preferred plan.

I. Generation and Purchase Power Forecast

Q. Have you developed a generation and purchase power forecast for I&M to meet its customers' projected demands?

A. Yes. A forecast of generation (net energy output) from I&M's generating units and purchased power was developed for the five-year forecast period to meet I&M's Total System Load obligations as shown in Exhibits IM-3 (HAB-3) and IM-4 (HAB-4). The generation and purchase power forecast is presented by month in Exhibit IM-8 (HAB-8) for 2017, and annually in Exhibit IM-9 (HAB-9) for the years 2017 - 2021.

Q. Please explain how the generation and purchase power forecast for I&M was developed.

A. I&M's generation sources for the forecast period include Rockport (I&M's share), the Cook Nuclear Plant, small hydroelectric plants located on the St. Joseph River in Michigan and Indiana, and solar power generation. The monthly and annual output of the hydroelectric plants was estimated, based on their historical average energy production. Nuclear energy production projections take into account maintenance and refueling requirements, and projected outage and other curtailment rates. Solar generation is estimated based on the projected capability of each installation as well as the typical insolation patterns for the region.

I&M's generating units are operated along with the units of the other PJM members, to meet the total PJM load requirements on the most economical basis, based on price offers, subject to transmission limitations. Such operation was simulated in the development of the generation forecast by means of the *PLEXOS*® simulation model, a production-costing computer program developed by Energy Exemplar.

Q. Please explain the Purchased Power projections in Exhibits IM-8 (HAB-8) and IM-9 (HAB-9).

A. I&M's Purchased Power for the forecast period consists of energy from: I&M's Unit Power purchase from AEG (from Rockport Units 1 and 2); I&M's share of purchases from the Ohio Valley Electric Corporation, wind and solar energy purchases and other purchases (PJM market energy). The wind and solar purchases are estimated based on historical patterns.

J. Conclusion

Q. In your opinion, with regard to the areas covered in your testimony, is the power supply cost recovery plan filed by I&M in this proceeding reasonable and prudent at this time?

A. Yes, I&M's power and energy requirements during the 12-month period covered by the plan (and during the five-year forecast period) will be supplied from its own generating units, its unit power purchase from AEG, committed purchases, along with other purchases from affiliates or from the extensive PJM system.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Indiana Michigan Power Company
Seasonal and Annual Peak Internal Demands, Energy Requirements and Load Factor
2006-2021

	Winter Peak (a)			Summer Peak			Annual Peak, Energy and Load Factor				
	Date	MW	% Growth	Date	MW	% Growth	MW	%Growth	GWh	%Growth	Load Factor %
Actual											
2006	12/08/05	3,537	---	07/31/06	4,650	---	4,650	---	24,421.0	---	60.0
2007	02/06/07	3,945	11.5	08/07/07	4,528	-2.6	4,528	-2.6	26,003.9	6.5	65.6
2008	01/25/08	3,875	-1.8	07/31/08	4,264	-5.8	4,264	-5.8	25,445.5	-2.1	67.9
2009	01/15/09	3,728	-3.8	06/25/09	4,262	0.0	4,262	0.0	24,297.0	-4.5	65.1
2010	12/10/09	3,858	3.5	07/23/10	4,474	5.0	4,474	5.0	25,829.4	6.3	65.9
2011	12/13/10	3,785	-1.9	07/21/11	4,837	8.1	4,837	8.1	25,928.6	0.4	61.2
2012	01/20/12	3,686	-2.6	07/06/12	4,726	-2.3	4,726	-2.3	25,731.0	-0.8	62.0
2013	01/22/13	3,782	2.6	09/10/13	4,540	-3.9	4,540	-3.9	25,719.1	0.0	64.7
2014	01/22/14	3,938	4.1	09/05/14	4,388	-3.4	4,388	-3.4	25,741.2	0.1	67.0
2015	01/14/15	3,952	0.4	07/28/15	4,398	0.2	4,398	0.2	25,046.6	-2.7	65.0
Forecast											
2016(b)		3,702	-6.3		4,438	0.9	4,438	0.9	24,967.0	-0.3	64.0
2017		3,697	-0.1		4,442	0.1	4,442	0.1	24,809.4	-0.6	63.8
2018(c)		3,621	-2.1		4,356	-1.9	4,356	-1.9	24,280.7	-2.1	63.6
2019(c)		3,613	-0.2		4,319	-0.9	4,319	-0.9	24,185.4	-0.4	63.9
2020(c)		3,594	-0.5		3,969	-8.1	3,969	-8.1	23,129.5	-4.4	66.3
2021(c)		3,363	-6.4		3,995	0.7	3,995	0.7	22,522.9	-2.6	64.4
Average Annual Growth Rates:											
2006-2015			1.2			-0.6		-0.6		0.3	
2016-2021			-1.9			-2.1		-2.1		-2.0	

Notes: (a) Actual winter peak for a year may occur in the 1st quarter of that year or in the 4th quarter of the preceding year.
(b) To date, actual winter 2016/17 peak is 3,702 MW, which occurred on 01/13/16, actual summer 2016 peak is 4,546 MW, which occurred on 08/11/16.
(c) Beginning in 2018, the internal demand reflects decreasing levels of wholesale load.

Indiana Michigan Power Company
Annual Internal Energy Requirements
2006-2021

	Residential Sales		Commercial Sales		Industrial Sales		Other (a) Requirements		Total Internal Energy Requirements	
	GWh	%Growth	GWh	%Growth	GWh	%Growth	GWh	%Growth	GWh	%Growth
Actual										
2006	5,783.9	---	5,067.7	---	8,049.2	---	5,520.2	---	24,421.0	---
2007	6,131.7	6.0	5,373.3	6.0	7,967.1	-1.0	6,531.7	18.3	26,003.9	6.5
2008	6,058.6	-1.2	5,272.0	-1.9	7,535.7	-5.4	6,579.2	0.7	25,445.5	-2.1
2009	5,766.8	-4.8	5,038.4	-4.4	6,761.9	-10.3	6,730.0	2.3	24,297.0	-4.5
2010	6,083.1	5.5	5,121.0	1.6	7,444.9	10.1	7,180.4	6.7	25,829.4	6.3
2011	5,997.3	-1.4	5,044.9	-1.5	7,522.9	1.0	7,363.4	2.5	25,928.6	0.4
2012	5,770.9	-3.8	5,001.1	-0.9	7,556.4	0.4	7,402.6	0.5	25,731.0	-0.8
2013	5,778.5	0.1	4,942.6	-1.2	7,521.7	-0.5	7,476.4	1.0	25,719.1	0.0
2014	5,775.8	0.0	4,883.6	-1.2	7,640.0	1.6	7,441.8	-0.5	25,741.2	0.1
2015	5,482.9	-5.1	4,891.5	0.2	7,569.9	-0.9	7,102.2	-4.6	25,046.6	-2.7
Forecast										
2016	5,416.2	-1.2	4,842.0	-1.0	7,696.4	1.7	7,012.2	-1.3	24,967.0	-0.3
2017	5,286.6	-2.4	4,746.0	-2.0	7,581.9	-1.5	7,194.9	2.6	24,809.4	-0.6
2018	5,240.1	-0.9	4,794.0	1.0	7,607.9	0.3	6,638.6	-7.7	24,280.7	-2.1
2019	5,132.2	-2.1	4,841.7	1.0	7,646.5	0.5	6,564.9	-1.1	24,185.4	-0.4
2020	5,068.0	-1.3	4,862.6	0.4	7,639.0	-0.1	5,559.8	-15.3	23,129.5	-4.4
2021	5,084.1	0.3	4,893.5	0.6	7,649.7	0.1	4,895.6	-11.9	22,522.9	-2.6
Average Annual Growth Rates										
2006-2015		-0.6		-0.4		-0.7		2.8		0.3
2016-2021		-1.3		0.2		-0.1		-6.9		-2.0

Notes: (a) Other requirements includes other internal sales, and losses and energy unaccounted for. Beginning in 2018, the internal demand reflects decreasing levels of wholesale load.

Indiana Michigan Power Company
Monthly and Annual Energy Sales, Internal and System Loads
2017
(Thousands of Megawatthours)

Line No.	Energy Sales to Ultimate Customers	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1.	Residential	617.3	485.7	451.6	330.4	352.8	404.4	527.5	526.8	360.8	341.0	369.4	518.9	5,286.6
2.	Commercial	410.5	361.6	373.3	336.4	392.0	430.3	454.0	451.5	379.8	399.3	360.2	397.1	4,746.0
3.	Industrial	617.3	622.6	637.2	615.9	663.6	642.6	637.0	647.3	589.6	652.9	632.0	624.0	7,581.9
4.	Other Ultimate	7.5	6.2	6.1	5.3	5.0	4.7	4.9	5.3	5.5	6.5	6.9	7.3	71.4
5.	Total Ultimate Sales	1,652.6	1,476.1	1,468.2	1,288.1	1,413.5	1,482.0	1,623.4	1,630.9	1,335.7	1,399.7	1,368.5	1,547.3	17,686.0
	Energy Sales for Resale to Internal Customers													
6.	Municipals and Cooperatives	439.2	405.2	412.6	389.2	404.9	418.9	455.1	464.7	411.0	402.8	402.2	432.2	5,037.9
7.	Total Internal Sales for Resale	439.2	405.2	412.6	389.2	404.9	418.9	455.1	464.7	411.0	402.8	402.2	432.2	5,037.9
	Internal Load													
8.	Total Internal Sales (Sum 5 and 7)	2,091.8	1,881.3	1,880.8	1,677.2	1,818.4	1,900.9	2,078.5	2,095.6	1,746.6	1,802.5	1,770.7	1,979.5	22,723.9
9.	Total Losses	163.4	146.7	212.8	190.0	130.7	203.4	236.2	133.6	186.7	148.8	200.3	132.9	2,085.6
10.	Total Unadjusted Internal Load	2,255.2	2,028.0	2,093.6	1,867.2	1,949.1	2,104.4	2,314.7	2,229.1	1,933.4	1,951.3	1,971.1	2,112.5	24,809.4
11.	PJM Marginal Losses	(52.3)	(46.9)	(48.4)	(43.0)	(45.4)	(48.8)	(53.6)	(51.9)	(44.7)	(45.2)	(45.7)	(48.6)	(574.6)
12.	Total Internal Load	2,203.0	1,981.1	2,045.1	1,824.2	1,903.7	2,055.5	2,261.1	2,177.2	1,888.7	1,906.0	1,925.4	2,063.9	24,234.9
	Energy Sales for Resale													
13.	I&M System Sales	962.4	955.9	552.0	490.9	291.2	527.8	539.8	517.2	333.3	246.6	275.1	946.5	6,638.7
14.	Total Sales for Resale to Non-Associated Systems	962.4	955.9	552.0	490.9	291.2	527.8	539.8	517.2	333.3	246.6	275.1	946.5	6,638.7
15.	Total System Load (Sum of 12 and 14)	3,165.4	2,937.0	2,597.1	2,315.1	2,194.9	2,583.4	2,800.9	2,694.4	2,222.0	2,152.7	2,200.5	3,010.4	30,873.6

Indiana Michigan Power Company
Annual Energy Sales, Internal and System Loads
2017 - 2021
(Thousands of Megawatthours)

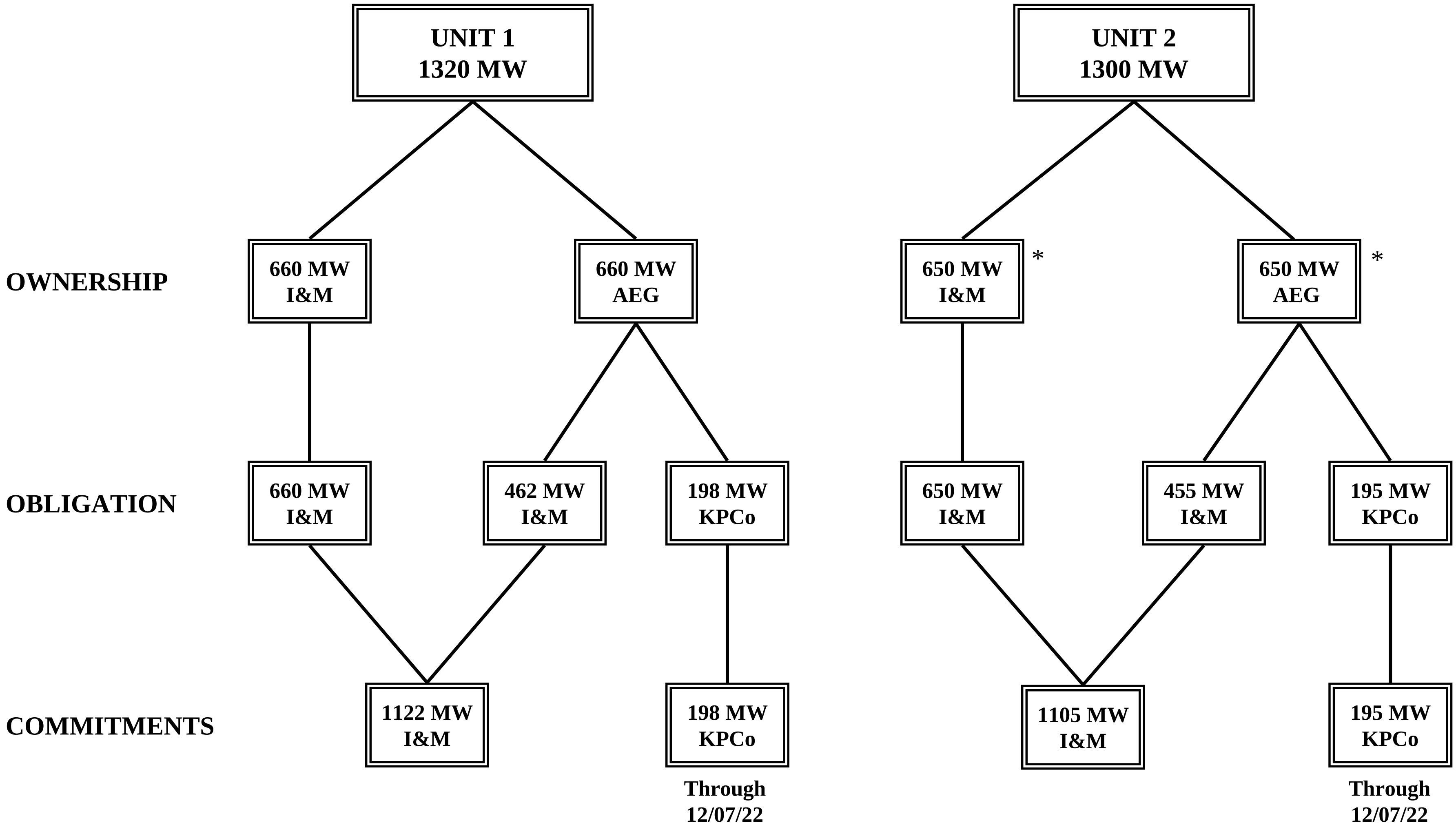
Line No.	Energy Sales to Ultimate Customers	2017	2018	2019	2020	2021
1.	Residential	5,286.6	5,240.1	5,132.2	5,068.0	5,084.1
2.	Commercial	4,746.0	4,794.0	4,841.7	4,862.6	4,893.5
3.	Industrial	7,581.9	7,607.9	7,646.5	7,639.0	7,649.7
4.	Other Ultimate	71.4	71.6	71.8	71.8	71.8
5.	Total Ultimate Sales	17,686.0	17,713.7	17,692.2	17,641.4	17,699.1
	Energy Sales for Resale to Internal Customers					
6.	Municipals and Cooperatives	5,037.9	4,550.4	4,501.8	3,523.8	2,905.1
7.	Total Internal Sales for Resale	5,037.9	4,550.4	4,501.8	3,523.8	2,905.1
	Internal Load					
8.	Total Internal Sales (Sum 5 and 7)	22,723.9	22,264.1	22,194.0	21,165.2	20,604.2
9.	Total Losses	2,085.6	2,016.6	1,991.3	1,964.3	1,918.7
10.	Total Unadjusted Internal Load	24,809.4	24,280.7	24,185.4	23,129.5	22,522.9
11.	PJM Marginal Losses	(574.6)	(562.4)	(560.2)	(535.7)	(521.5)
12.	Total Internal Load	24,234.9	23,718.2	23,625.2	22,593.8	22,001.4
	Energy Sales for Resale					
13.	I&M System Sales	6,638.7	8,245.5	7,703.4	8,421.7	8,891.7
14.	Total Sales for Resale to Non-Associated Systems	6,638.7	8,245.5	7,703.4	8,421.7	8,891.7
15.	Total System Load (Sum of 12 and 14)	30,873.6	31,963.8	31,328.5	31,015.4	30,893.1

INDIANA MICHIGAN POWER COMPANY
EXPECTED SUMMER 2017 CAPACITY RESOURCES

			CAPABILITY - MW(a)	
Plant	**Unit**	**Notes**	**ICAP**	**UCAP(b)**
Cook	1		1,006	971
Cook	2		1,148	1,109
Rockport	1		1,118	1,079
Rockport	2		1,105	1,067
Berrien Springs	1-12		6	6
Buchanan	1-10		3	3
Constantine	1-4		1	1
Elkhart	1-3		2	2
Mottville	1-4		2	2
Twin Branch	1-8		5	5
Deer Creek (Solar)	1	(c)	3	1
Olive (Solar)	1	(c)	5	2
Twin Branch (Solar)	1	(c)	3	1
Waterviliet (Solar)	1	(c)	5	2
	Total		4,410	4,250
Committed Purchases				
OVEC	1-6	(d)	166	160
Fowler Ridge Phase 1 (Wind)		(c,e)	100	11
Fowler Ridge Phase 2 (Wind)		(c,f)	50	7
Wildcat (Wind)		(c,g)	100	13
Headwaters (Wind)		(c,h)	200	26
Total Committed Purchases			616	217
Uncommitted Purchases			-	0
Total Incl. Purchases			5,027	4,467

Notes:
- a. Expected capacity at time of I&M Summer 2017 peak.
- b. Based on 12-month avg. AEP EFORd in eCapacity as of twelve months ended 9/30 of the previous year.
- c. Wind & solar UCAP values are 13% & 38%, respectively, of nameplate or based on historical performance.
- d. I&M's PPR share of OVEC purchase. Agreement extends through March 13, 2026.
- e. Agreement extends through January 31, 2029.
- f. Agreement extends through December 17, 2029.
- g. Agreement extends through January 15, 2033.
- h. Agreement extends through December 22, 2034.

ROCKPORT PLANT
OWNERSHIP, OBLIGATION AND COMMITMENTS



* Both I&M and AEG sell and leaseback their respective shares of Rockport Unit 2. The lessors are non-affiliated, non-utility institutions. During the term of the lease, I&M and AEG each has full entitlement to 50% of the power and energy from Rockport Unit 2.

INDIANA MICHIGAN POWER COMPANY
Projected Summer Peak Demands, Generating Capabilities, and Margins
(2017/18 - 2021/22)

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)
					=(1)+(3)				=[(4)-((5)*(6))]*(7)			=(9)*(1-(10))						=(11)+(12)+(13) Σ(15)+(16)	=(17)-(8)		=[(8)+(5)*(6)*(7)]/(1+(19))	=(18)/(20)	=(19)+(21)
		Obligation to PJM								Resources									PJM Reserve Margin Position				
										ICAP		UCAP	UCAP	UCAP		UCAP	UCAP	UCAP	UCAP		UCAP		
Planning Year		Internal Demand(a)	DSM(b)	Projected DSM Impact(c)	Net Internal Demand	Interruptible Demand Response(d)	Demand Response Factor	Forecast Pool Req't(e)	UCAP Obligation	Existing ICAP & Planned Changes(f)	AEP EFORd(g)	Existing UCAP & Planned Changes	Net Capacity Offsets(h)	Wind & Solar Purchases(i)	Planned Additions Units	Planned Additions MW	Annual Capacity Purchases(j)	Total Available UCAP	I&M Net Capacity Position	Installed Reserve Margin	Total UCAP Obligation Less IDR and IRM	I&M Reserve Margin Above PJM IRM	Total I&M Reserve Margin
2017/18	(k)	4,264	(69)	0	4,264	223	0.953	1.088	4,408	4,567	3.44%	4,410	(9)	56				4,457	49	16.50%	3,982	1.23%	17.73%
2018/19	(k)	4,185	(65)	0	4,185	223	0.953	1.088	4,323	4,598	3.45%	4,439	(6)	56				4,490	167	16.50%	3,909	4.27%	20.77%
2019/20	(k)	4,193	(56)	0	4,193	223	0.953	1.088	4,331	4,598	3.45%	4,439	(4)	56				4,491	160	16.50%	3,916	4.09%	20.59%
2020/21	(a)	3,824	(46)	(36)	3,788	309	0.953	1.088	3,801	4,628	3.45%	4,453	65	8				4,525	724	16.50%	3,538	20.47%	36.97%
2021/22	(a)	3,837	(34)	(69)	3,768	309	0.953	1.088	3,780	4,628	3.45%	4,453	65	19				4,536	756	16.50%	3,519	21.48%	37.98%

Notes: (a) Based on 2016 Load Forecast (with implied PJM diversity factor). Beginning in 2018, the internal demand reflects decreasing levels of wholesale load.

(b) Existing plus approved and projected "Passive" EE, and IVV;
(note: these values & timing are for reference only and are not reflected in position determination).

(c) For PJM planning purposes, the ultimate impact of new DSM is 'delayed' ≈ 4 years to represent the ultimate recognition of these amounts through the PJM-originated load forecast process.

(d) Interruptible Demand Response (IDR) approved by PJM in the prior planning year plus forecasted "Active" DR.

(e) Installed Reserve Margin (IRM) = 16.5%
Forecast Pool Requirement (FPR) = (1 + IRM) * (1 - PJM EFORd)

(f) Reflects the members ownership ratio of following summer capability assumptions:
I&M share of OVEC capacity (7.85% PPR-share of full ≈ 2,180 total capacity)
EFFICIENCY IMPROVEMENTS:
2018/19: Rockport 1: 36 MW, I&M share: 31 MW (turbine uprate)
2020/21: Rockport 2: 36 MW, I&M share: 31 MW (turbine uprate)

(g) Based on 12-month avg. AEP EFORd in eCapacity as of twelve months ended 9/30 of the previous year.

(h) Incudes estimated I&M nominations for PJM EE ('passive' DR program) levels--reflected as a UCAP resource as part of PJM's emerging auction products and estimated PJM Capacity Performance adjustments.

(i) Wind & solar UCAP values are assumed to be 13% & 38% (respectively) of nameplate or based on historical performance through 2019/20.
Wind capacity removed beginning in 2020/21 in reflection of the PJM Capacity Performance standard.

(j) Affiliate capacity purchases (in accordance with AEP PCA) necessary to meet required PJM IRM.

(k) PJM forecast.

INDIANA MICHIGAN POWER COMPANY
Sources of Energy
2017
(Thousands of Megawatthours)

Line No.		Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total
1	**GENERATION**													
2	**Fossil**	780.3	752.7	445.4	335.7	251.8	529.0	644.7	580.1	418.1	525.3	481.4	698.8	6,443.2
3	**Nuclear**	1,588.9	1,435.1	1,588.9	1,537.6	1,557.8	1,493.9	1,522.4	1,524.6	1,220.9	817.8	845.6	1,588.9	16,722.4
4	**Hydro**	10.2	9.5	11.6	12.1	10.3	9.0	8.2	7.4	7.1	7.3	8.6	10.8	112.1
5	**Solar**	1.0	1.3	2.1	2.4	2.9	3.0	3.0	2.7	2.3	1.8	1.0	0.8	24.4
6	**Total Generation**	2,380.5	2,198.7	2,048.0	1,887.8	1,822.8	2,034.9	2,178.3	2,114.8	1,648.4	1,352.1	1,336.6	2,299.3	23,302.1
7	**PURCHASED POWER**													
8	**AEG**	546.2	526.9	311.8	235.0	176.3	370.3	451.3	406.1	292.7	367.7	337.0	489.2	4,510.2
9	**OVEC**	82.4	76.5	58.2	41.2	51.3	59.8	66.4	63.2	50.3	33.1	47.2	59.4	689.2
10	**Wind**	152.8	131.2	141.0	142.0	112.7	81.6	59.5	47.8	59.1	123.9	150.3	146.2	1,348.1
11	**Solar**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	**Other Purchase**	3.5	3.7	38.3	9.0	31.8	36.8	45.4	62.4	171.5	275.9	329.4	16.3	1,024.1
13	**Total Purchased Power**	784.9	738.3	549.1	427.2	372.2	548.5	622.6	579.6	573.6	800.6	863.9	711.1	7,571.5
14	**TOTAL SOURCES OF ENERGY**	3,165.4	2,937.0	2,597.1	2,315.1	2,194.9	2,583.4	2,800.9	2,694.4	2,222.0	2,152.7	2,200.5	3,010.4	30,873.6

INDIANA MICHIGAN POWER COMPANY
Sources of Energy
2017 - 2021
(Thousands of Megawatthours)

Line No.		2017	2018	2019	2020	2021
1	GENERATION					
2	Fossil	6,443.2	6,948.2	6,955.6	5,980.9	5,983.0
3	Nuclear	16,722.4	17,616.9	16,799.8	17,750.8	17,616.1
4	Hydro	112.1	110.1	111.7	111.4	111.4
5	Solar	24.4	24.3	24.2	24.1	23.9
6	Total Generation	23,302.1	24,699.5	23,891.3	23,867.2	23,734.5
7	PURCHASED POWER					
8	AEG	4,510.2	4,863.7	4,868.9	4,186.6	4,188.1
9	OVEC	689.2	686.0	688.2	688.5	689.5
10	Wind	1,348.1	1,348.1	1,348.1	1,853.5	1,847.4
11	Solar	0.0	0.0	0.0	30.8	76.6
12	Other Purchase	1,024.1	366.5	532.1	388.8	357.1
13	Total Purchased Power	7,571.5	7,264.3	7,437.3	7,148.2	7,158.7
14	TOTAL SOURCES OF ENERGY	30,873.6	31,963.8	31,328.5	31,015.4	30,893.1

DIRECT TESTIMONY OF MICKEY L. BELLVILLE
ON BEHALF OF
INDIANA MICHIGAN POWER COMPANY
2017 PSCR PLAN CASE

Q. Please state your name and business address.

A. My name is Mickey L. Bellville and my business address is 500 Circle Drive, Buchanan, Michigan 49107.

Q. By whom are you employed and in what capacity?

A. I am employed by Indiana Michigan Power Company (I&M or Company) as the Manager of Nuclear Engineering, which coordinates the supply and management of nuclear fuel and related services for the Donald C. Cook Nuclear Plant (Cook Nuclear Plant). My responsibilities include supervising activities related to the supply of nuclear fuel, including its procurement, safety analysis, performance, disposal, reload licensing, reactor engineering and plant support.

Q. Please briefly describe your educational background.

A. In 1982, I graduated from the University of Michigan with a Bachelor of Science degree in Engineering. In 1999, I received a Master of Business Administration degree from Bethel College.

Q. Please briefly describe your professional background.

A. From May 1982 to March 1995, as an Engineer with Duke Power Company, I was involved with commercial nuclear fuel contract development, contract language interpretation, and contract negotiations. I was responsible for developing procurement strategy, economic analysis, budget preparation, and negotiation strategy and techniques.

From March 1995 to July 1996, I was employed as an Engineer at Consumers Power Company and was responsible for front end fuel cycle coordination, technical reload interface, economic analysis coordination, vendor interface for fuel management activities, budgetary control, cost/risk analysis, and fuel planning and scheduling.

From July 1996 to February 2004, while being employed by my current employer, I&M, I held responsibilities for developing a strategic partnership contract with Framatome, Inc. that included services for engineering, projects, and outage services at cost, including profit/incentives based on performance metrics. In addition, I evaluated projects through financial analysis and capital project planning and budgeting.

From February 2004 to May 2004, I held Project Manager responsibilities that included project management for the Fuel Transition Project (FTP). Areas of management for the FTP included safety analysis, licensing, neutronics, Framatome interface, and budgetary controls.

From May 2004 to February 2007, I was the Nuclear Fuel Supervisor and my responsibilities included core reload activities, fuel procurement, cost recovery filings, vendor manufacturing oversight, regulatory administration, fuel integrity monitoring, fuel inspection coordination, and Updated Final Safety Analysis Report modifications.

Beginning in February 2007, I became the Manager of Nuclear Engineering and my responsibilities include oversight of all nuclear fuel, safety analysis, and reactor engineering activities in support of Cook Nuclear Plant.

Q. Have you previously testified or submitted testimony in any regulatory proceedings?

A. Yes. I have submitted testimony to the Michigan Public Service Commission in I&M's 2006 through 2015 Power Supply Cost Recovery (PSCR) Reconciliation Cases and I&M's 2008 through 2016 PSCR Plan Cases. In addition, I have submitted testimony before the Indiana Utility Regulatory Commission in I&M fuel cost proceedings.

Q. What is the purpose of your testimony in this case?

A. The purpose of my testimony in this case is to: (1) describe the relevant responsibilities of the Nuclear Engineering Department as they pertain to the 2017 nuclear fuel costs, (2) support projected nuclear fuel costs used by Witness Heimberger, (3) describe major nuclear fuel contracts that affect I&M's 2017 nuclear fuel costs, and (4) discuss the reasonableness and prudence of the actions taken to minimize I&M's actual nuclear fuel costs.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring Exhibits IM-10 (MLB-1) and IM-11 (MLB-2) that provide the monthly expensing of nuclear fuel costs.

Q. Do you adopt these exhibits in support of the PSCR Plan Case?

A. Yes.

Q. What are the responsibilities of the Nuclear Engineering Department as it relates to nuclear fuel requirements and nuclear fuel related activities?

A. The responsibilities of the Nuclear Engineering Department as it relates to nuclear fuel requirements and related activities are:

- To constantly monitor and evaluate market, political, regulatory, and technical conditions that may affect the secure supply of economical and licensable nuclear fuel.
- To prepare bid specifications and evaluate bid proposals for the purchase of nuclear fuel and nuclear fuel related services, as well as the storage, shipping, and disposal of spent nuclear fuel.
- To negotiate contracts with suppliers of nuclear fuel and nuclear fuel related services.
- To establish the most economic operating parameters of each cycle with consideration of the operating requirements of the American Electric Power (AEP) System.
- To evaluate and select economic core loading plans and to administer the purchase schedule and contracts necessary to implement these plans.
- To provide support to a nuclear fuel quality assurance program for the purpose of assuring that the nuclear fuel is built according to its design criteria and specifications.

- To perform nuclear fuel economic analyses and provide current data and projections of future expenditures to other departments within AEP and I&M.
- To have core physics parameters verified to insure that the operation and performance of the nuclear fuel is within safety limits and agree with predictions.
- To ensure that the required logistics of the nuclear fuel cycle takes place for each reload batch, consisting of new nuclear fuel assemblies placed in the reactor core during a refueling outage. This may include uranium mining and milling, conversion to uranium hexafluoride, enrichment, fuel fabrication, fuel assembly shipment, and reactor refueling operations.

Q. Please describe the major contracts entered into by I&M for supplying nuclear fuel to the Cook Nuclear Plant that affect the expected 2017 nuclear fuel costs.

A. A summary of the major contracts I&M entered into for the supply and disposal of nuclear fuel for Cook Nuclear Plant that will affect the 2017 costs follows:

1. <u>Long-Term Contracts</u>

   a. Westinghouse Electric Company
      Contract dated June 1, 2012
      Nuclear Fuel Fabrication

This contract calls for the design and fabrication of multiple reload batches of nuclear fuel for Units 1 and 2 of the Cook Nuclear Plant. The first reload batch under this contract was delivered in 2013. The contract includes fabrication of the fuel assemblies and all transportation of special nuclear material, fuel assemblies, and components incident to the fabrication process.

b. United States of America (Department of Energy [DOE] as representative)

Contract dated June 13, 1983

Nuclear Waste Disposal

I&M has contracted with the DOE to take title to and dispose of the spent nuclear fuel or high-level waste. I&M's PSCR Plan Case includes post-April 6, 1983, spent nuclear fuel fees.

2. Mid-Term Contracts

a. Cameco (uranium hexafluoride)

b. Areva (enriched uranium)

These contracts are for the procurement of materials and services on a two- to five-year basis.

3. Spot Procurement Agreements and Short-Term Contracts

a. UG USA, Inc (uranium hexafluoride)

b. ConverDyn (uranium hexafluoride)

c. United States Enrichment Corporation (enriched uranium)

These agreements and contracts are for the procurement of materials and services for the fuel cycle on a one-time spot procurement or short-term basis.

Q. Can you briefly describe the long-term contract associated with nuclear waste disposal?

A. Yes. The Nuclear Waste Policy Act (NWPA) of 1982 established that the Federal government had responsibility to provide for the permanent disposal of spent nuclear fuel (SNF). Thereafter, the DOE entered into standard contracts for the disposal of SNF and the standard contracts provided for a fee to be paid by generators and owners of the SNF. Nuclear utilities, including I&M, had no practical alternatives other than to sign standard contracts with the DOE in order to obtain and maintain operating licenses. I&M's contract with the DOE and the DOE's obligation under the contract remain in effect.

Q. How were I&M's projected post-April 6, 1983, SNF costs determined?

A. Projected post-April 6, 1983, SNF costs were calculated based on the rate of one mill per kilowatt-hour (kWh) of electricity generated and sold in accordance with the NWPA of 1982. However, the Department of Energy provided notice that effective May 16, 2014, the Spent Nuclear Fuel Disposal Fee will be 0.0 mill per kWh of electricity generated and sold. This is reflected in Exhibits IM-10 (MLB-1) and IM-11 (MLB-2).

Q. Will I&M have any intermediate actions for managing SNF, prior to permanent disposal as established in the NWPA of 1982?

A. Yes. The Federal government currently does not have a permanent disposal facility in operation. As such, I&M will be required to store SNF at Cook Nuclear Plant's site in canisters that will then be loaded into Dry Storage Casks until permanent disposal becomes available.

Q. Will this canister storage of SNF affect the expected 2017 nuclear fuel costs?

A. No.

Q. Please describe any additional obligations entered into by I&M that do affect the expected 2017 nuclear fuel costs.

A. Cook Nuclear Plant has entered into Nuclear Fuel Leases for reload batches and costs associated with these leases include the monthly rent component, finance charges, and administration fees. The monthly rent component for the nuclear fuel is determined by multiplying the number of BTUs consumed by the nuclear fuel during such month and the dollar amount per BTU (BTU charge) as established in an individual leasing record. During months for which no BTUs are consumed, the only expenses incurred include the finance charges and administration fees.

Table 1: Active Leases Affecting 2017 Fuel Costs

Unit	Batch	Provider	Effective Date
1	27	Mizuho Corporate Bank / DCC Fuel VI, LLC	05/16/2013 through 10/20/2017
2	23	Sumitomo Mitsui Banking Corp / IMP-11-2013	11/15/2013 through 05/15/2018
1	28	Mizuho Corporate Bank / DCC Fuel VII, LLC	10/28/2014 through 04/28/2019
2	24	Bank of America Leasing BSC, LLC / DCC Fuel VIII	4/27/2015 through 10/27/2019
1	29	Huntington National Bank / DCC Fuel IX	04/28/2016 through 10/29/2020

The lease terms are for a period not to exceed sixty (60) months.

Q. Why did I&M enter into these obligations?

A. Nuclear Fuel Leases in the current environment provide a lower cost financing option versus using internal capital funds to purchase the fuel.

Q. Will these fuel leases affect the projected 2017 nuclear fuel costs?

A. Yes, as shown in Exhibits IM-10 (MLB-1) and IM-11 (MLB-2), the projected 2017 nuclear fuel costs will be impacted. In particular, basic rent, financing charges and other administrative fees will be applied. This is the result of the continued service in 2017 of Unit 1 Batch 27, 28 and 29 as well as Unit 2 Batches 23 and 24.

Q. Will these fuel leases also affect the projected nuclear fuel costs beyond 2017?

A. Yes, the impact of these leases on projected nuclear fuel costs for 2017-2021 are also shown on the exhibits.

Q. Does I&M's projected forecast for 2017 include a refueling outage?

A. Yes. Unit 1 is scheduled to be refueled beginning in September 2017.

Q. What is the projected schedule for the September 2017 refueling outage?

A. The forecast reflects the September 2017 Unit 1 refueling outage includes an additional 30 days for inspection (and repair if needed) of the reactor vessel baffle bolts. During the spring of 2016, two other nuclear plants designed similar to DC Cook experienced baffle bolt degradation issues, resulting in the emergent need to repair baffle bolts. The nuclear industry reviewed previous baffle bolt degradation operating experience and recommended guidance on the repair of the baffle bolts in plants such as DC Cook Unit's 1 and 2. This Nuclear Regulatory Committee approved guidance requires ultrasonic inspection of the baffle bolts as well as a minimum bolting pattern for repairs, if necessary.

Q. Please provide a brief description of a reactor vessel baffle bolt.

A. A baffle bolt is a stainless steel bolt that attaches flat metal panels called baffle plates that line the inside of the core barrel of pressurized water reactors. Baffle plate liners form a precise vertical support structure for the uranium fuel assemblies that comprise the reactor core, enabling the rectangular fuel assemblies to be held securely inside the cylindrical core barrel. The baffle plates also serve to direct the flow of cooling water through the reactor.

Q. Mr. Bellville, please discuss the actions taken by I&M that will help to minimize the projected 2017 nuclear fuel costs.

A. The actions taken by I&M to minimize the cost of nuclear fuel occur primarily as part of the long-term planning and competitive bidding processes for nuclear fuel supply to the Cook Nuclear Plant. The Cook Nuclear Plant units are refueled on an 18-month cycle and a reload batch can remain in the reactor for many years; therefore, nuclear fuel cost savings achieved through long-term planning and competitive bidding are realized over a period of years as the fuel is consumed for the production of electricity.

Another way the cost of nuclear fuel is minimized is through the judicious use of the secondary nuclear fuel market. Excess inventories and production capabilities in the nuclear fuel market have made it possible for I&M to purchase uranium hexafluoride on the secondary market for Cook Nuclear Plant. The uranium hexafluoride purchases have eliminated I&M's carrying costs for uranium during conversion. The logistics of providing the uranium hexafluoride to the enrichment facility are generally accomplished by an accounting transfer of the material, which reduces risk for I&M. Similarly, the enriched uranium is transferred to the fuel fabricator through an accounting transaction, which also reduces risk for I&M.

Yet another example of nuclear fuel cost minimization is the examination, and revision when economically justified, of the fuel loadings that fabricators propose to the Company. Technical evaluations of nuclear fuel cycle designs have also been effective in improving the negotiating position of I&M during the fuel fabrication contract administration. A detailed analysis of a proposed design can show the impact of technical trade-offs made in new products offered by the fabrication vendors. I&M technical staff are involved in the vendor's reload design process so that the design process can occur during or just prior to a refueling outage. This compressed design schedule allows I&M to develop loading patterns that meet the changing energy or regulatory requirements with a minimum impact on fuel cycle economics.

Q. How much uranium does I&M have in inventory?

A. Inventory fluctuates depending on the timing of the reload batch to be delivered. Raw material is obtained to support near-term reloads. Also, small amounts exist as a result of final detailed fuel cycle and fuel assembly design. I&M continually monitors the performance of any vendor who is under contract to assure fulfillment of contractual obligations. By contracting with reliable and proven performers and continuously monitoring their performance, the Company can operate with confidence at a lower inventory level.

Operating at a relatively low inventory and utilizing the spot market allows I&M to take advantage of the secondary market and reduce fuel-carrying costs. However, a thorough knowledge of uranium market situations is necessary to determine when conditions justify a mid-term or long-term supply contract rather than spot market purchases.

I&M also optimizes the scheduling of purchases to coincide with needs and contract flexibility in order to hold a relatively low inventory. Any additional overage material held is to be promptly used in the next applicable reload and is of minimal impact to the 2017 fuel costs.

Q. How does I&M accomplish the goal of optimized scheduling with minimized inventory and carrying costs?

A. In developing contracts and making purchases, I&M carefully plans the lead time required to perform each phase of fuel processing. The target date from which decisions are made is the date the fabricated fuel is needed at Cook Nuclear Plant. Once the target date is established, it is then necessary to identify when the fabricator must have the enriched uranium. I&M continuously monitors the long term generation schedule and the impacts changes to the generation schedule have on fuel procurement activities.

In addition, when possible, I&M negotiates payment arrangements that will occur as long after performance of the work as reasonably possible. Delaying the time that payment is required directly translates into reduced nuclear fuel costs by reducing carrying costs for a fuel reload.

Q. Are there other actions taken to minimize I&M's fuel cycle costs?

A. Yes. Because the Cook Nuclear Plant is the most economical fuel cost steam plant on the AEP System, both of the Cook Nuclear Plant units are base-loaded. Accordingly, I&M's policy is to operate them at a steady state maximum power level unless other operational restrictions apply. Because changes in power level create additional stress on the nuclear fuel assemblies, I&M strives to have these load changes performed as a planned maneuver and at proceduralized and conservative rates of change.

Along these same lines, I&M has developed an extensive capability in neutronic analysis. This allows I&M to develop for the Cook Nuclear Plant an optimized fuel management plan that considers the specific number of fuel assemblies to be loaded each cycle, what their corresponding uranium enrichment should be, which fuel assemblies should be removed from the core during the refueling, and how these new fuel assemblies and those remaining in the core should be rearranged during the refueling. As a result, I&M can meet its energy requirements while at the same time minimizing fuel cycle costs. This is a significant task, and to accomplish it, I&M has developed models of the reactor core utilizing sophisticated computer programs. These models are used to evaluate different reload arrangements proposed by fuel vendors to attain, within certain technical constraints, the goal of meeting I&M's energy requirements and minimizing fuel costs. Through this approach, I&M has been able to develop improved fuel management plans that lower fuel costs.

Q. Is there another area that you can point to that results in minimizing I&M's fuel costs?

A. Yes. The actions of the Company's technical staff to decrease the stress on the fuel during operation of the reactor are complemented by assuring that the fuel assemblies are built in accordance with design requirements. I&M operates under a Nuclear Regulatory Commission - approved Quality Assurance Program that requires the procurement of nuclear fuel from vendors with approved Quality Assurance programs which meet federal regulations. Periodic audits and process surveillances are required for all suppliers to assure that the supplier produces a finished product that fulfills all applicable design and specification criteria. These audits examine aspects of the manufacturing process, including raw materials, details of the design and design control, machined parts, sub-assemblies, components, and the finished fuel assemblies, to assure that corresponding specifications, drawings, and design criteria are met. These Quality Assurance Programs are intended to control the design and manufacturing process to assure a product of the highest quality.

The fuel fabrication contract gives I&M auditors significant authority to reject material at any stage and disqualify a supplier for nonperformance, resulting in a credible threat of contract termination if audit concerns are not addressed in a timely manner. The Quality Assurance Program minimizes fuel cycle cost by eliminating design errors and manufacturing mistakes and ensuring that the final product is capable of fulfilling its intended function.

Q. Have the actions taken by I&M to minimize nuclear fuel costs been effective?

A. Yes.

Q. In your opinion, has I&M made every reasonable effort to acquire nuclear fuel so as to provide electricity to its customers at the lowest nuclear fuel cost possible?

A. Yes.

Q. Does this complete your direct testimony?

A. Yes.

Indiana Michigan Power Company

Cook Unit 1 Monthly Expensing

2017

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Fuel Expense													
Net Generation (GWhT)	2335.3	2109.3	2335.3	2259.9	2335.3	2259.9	2335.3	2335.3	1431.3	0.0	150.7	2335.3	22222.7
Conv. Factor (BTU/Kwh)	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	
Generation (MBTU)	7,968,259	7,197,137	7,968,259	7,711,218	7,968,259	7,711,218	7,968,259	7,968,259	4,883,771	0	514,081	7,968,259	75,826,977
BTU Charge ($/MBTU)	0.7450	0.7450	0.7450	0.7450	0.7450	0.7450	0.7450	0.7450	0.7450	0.7450	0.7057	0.7057	
Fuel Expense	$ 5,936,563	$ 5,362,057	$ 5,936,563	$ 5,745,061	$ 5,936,563	$ 5,745,061	$ 5,936,563	$ 5,936,563	$ 3,638,539	$ -	$ 362,790	$ 5,623,240	$ 56,159,563
Monthly Expenses													
Fuel Expense	$ 5,936,563	$ 5,362,057	$ 5,936,563	$ 5,745,061	$ 5,936,563	$ 5,745,061	$ 5,936,563	$ 5,936,563	$ 3,638,539	$ -	$ 362,790	$ 5,623,240	$ 56,159,563
Post '83 SNF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 75,000	$ -	$ 75,000
Fuel Reload Engineering	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 300,000
Batch 27 Mizuho Lease Interest	$ 5,705	$ 5,705	$ 4,080	$ 4,080	$ 4,080	$ 2,508	$ 2,508	$ 2,508	$ 589	$ 589	$ 589		$ 32,941
Batch 28 Mizuho Lease Interest	$ 31,303	$ 24,482	$ 24,482	$ 24,482	$ 18,612	$ 18,612	$ 18,612	$ 12,608	$ 12,608	$ 12,608	$ 6,330	$ 6,330	$ 211,069
Total Monthly Expense	$ 5,998,571	$ 5,417,244	$ 5,990,125	$ 5,798,623	$ 5,984,255	$ 5,791,181	$ 5,982,683	$ 5,976,679	$ 3,676,736	$ 38,197	$ 469,709	$ 5,654,570	$ 56,778,573
Total Monthly Expense w/o SNF	$ 5,998,571	$ 5,417,244	$ 5,990,125	$ 5,798,623	$ 5,984,255	$ 5,791,181	$ 5,982,683	$ 5,976,679	$ 3,676,736	$ 38,197	$ 394,709	$ 5,654,570	$ 56,703,573
Generation (GWhE)	766.171	692.026	766.171	741.456	743.554	708.624	711.041	713.161	446.629	0.000	49.430	766.171	7,104.434
Mills/KWH	7.829	7.828	7.818	7.821	8.048	8.172	8.414	8.381	8.232	#DIV/0!	9.502	7.380	7.992
Mills/KWH w/o SNF	7.829	7.828	7.818	7.821	8.048	8.172	8.414	8.381	8.232	#DIV/0!	7.985	7.380	7.981

Indiana Michigan Power Company

Cook Unit 1 Monthly Expensing

2018

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Fuel Expense													
Net Generation (GWhT)	2335.3	2109.3	2335.3	2259.9	2335.3	2259.9	2335.3	2335.3	2259.9	2335.3	2259.9	2335.3	27495.9
Conv. Factor (BTU/Kwh)	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	
Generation (MBTU)	7,968,259	7,197,137	7,968,259	7,711,218	7,968,259	7,711,218	7,968,259	7,968,259	7,711,218	7,968,259	7,711,218	7,968,259	93,819,819
BTU Charge ($/MBTU)	0.7057	0.7057	0.7057	0.7057	0.7057	0.7057	0.7057	0.7057	0.7057	0.7057	0.7057	0.7057	
Fuel Expense	$ 5,623,240	$ 5,079,056	$ 5,623,240	$ 5,441,845	$ 5,623,240	$ 5,441,845	$ 5,623,240	$ 5,623,240	$ 5,441,845	$ 5,623,240	$ 5,441,845	$ 5,623,240	$ 66,209,119
Monthly Expenses													
Fuel Expense	$ 5,623,240	$ 5,079,056	$ 5,623,240	$ 5,441,845	$ 5,623,240	$ 5,441,845	$ 5,623,240	$ 5,623,240	$ 5,441,845	$ 5,623,240	$ 5,441,845	$ 5,623,240	$ 66,209,119
Post '83 SNF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 75,000	$ -	$ 75,000
Fuel Reload Engineering	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 300,000
Batch 28 Mizuho Lease Interest	$ 6,330	$ 5,575	$ 5,575	$ 5,575	$ 4,512	$ 4,512	$ 4,512	$ 3,411	$ 3,411	$ 3,411	$ 2,249	$ 2,249	$ 51,322
Total Monthly Expense	$ 5,654,570	$ 5,109,631	$ 5,653,815	$ 5,472,420	$ 5,652,752	$ 5,471,357	$ 5,652,752	$ 5,651,651	$ 5,470,256	$ 5,651,651	$ 5,544,094	$ 5,650,489	$ 66,635,441
Total Monthly Expense w/o SNF	$ 5,654,570	$ 5,109,631	$ 5,653,815	$ 5,472,420	$ 5,652,752	$ 5,471,357	$ 5,652,752	$ 5,651,651	$ 5,470,256	$ 5,651,651	$ 5,469,094	$ 5,650,489	$ 66,560,441
Generation (GWhE)	766.171	692.026	766.171	741.456	743.554	708.624	711.041	713.161	705.204	739.313	741.456	766.171	8,794.348
Mills/KWH	7.380	7.384	7.379	7.381	7.602	7.721	7.950	7.925	7.757	7.644	7.477	7.375	7.577
Mills/KWH w/o SNF	7.380	7.384	7.379	7.381	7.602	7.721	7.950	7.925	7.757	7.644	7.376	7.375	7.569

Indiana Michigan Power Company

Cook Unit 1 Monthly Expensing

2019

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Fuel Expense													
Net Generation (GWhT)	2335.3	2109.3	1431.3	904.0	2335.3	2259.9	2335.3	2335.3	2259.9	2335.3	2259.9	2335.3	25236.0
Conv. Factor (BTU/Kwh)	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	
Generation (MBTU)	7,968,259	7,197,137	4,883,771	3,084,487	7,968,259	7,711,218	7,968,259	7,968,259	7,711,218	7,968,259	7,711,218	7,968,259	86,108,601
BTU Charge ($/MBTU)	0.7057	0.7057	0.7057	0.7057	0.6175	0.6175	0.6175	0.6175	0.6175	0.6175	0.6175	0.6175	
Fuel Expense	$ 5,623,240	$ 5,079,056	$ 3,446,502	$ 2,176,738	$ 4,920,459	$ 4,761,735	$ 4,920,459	$ 4,920,459	$ 4,761,735	$ 4,920,459	$ 4,761,735	$ 4,920,459	$ 55,213,038
Monthly Expenses													
Fuel Expense	$ 5,623,240	$ 5,079,056	$ 3,446,502	$ 2,176,738	$ 4,920,459	$ 4,761,735	$ 4,920,459	$ 4,920,459	$ 4,761,735	$ 4,920,459	$ 4,761,735	$ 4,920,459	$ 55,213,038
Post '83 SNF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 75,000	$ -	$ 75,000
Fuel Reload Engineering	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 300,000
Batch 28 Mizuho Lease Interest	$ 2,249	$ 1,063	$ 1,063	$ 1,063	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,438
Total Monthly Expense	$ 5,650,489	$ 5,105,119	$ 3,472,565	$ 2,202,801	$ 4,945,459	$ 4,786,735	$ 4,945,459	$ 4,945,459	$ 4,786,735	$ 4,945,459	$ 4,861,735	$ 4,945,459	$ 55,593,476
Total Monthly Expense w/o SNF	$ 5,650,489	$ 5,105,119	$ 3,472,565	$ 2,202,801	$ 4,945,459	$ 4,786,735	$ 4,945,459	$ 4,945,459	$ 4,786,735	$ 4,945,459	$ 4,786,735	$ 4,945,459	$ 55,518,476
Generation (GWhE)	766.171	692.026	469.589	296.582	743.554	708.624	711.041	713.161	705.204	739.313	741.456	766.171	8,052.892
Mills/KWH	7.375	7.377	7.395	7.427	6.651	6.755	6.955	6.935	6.788	6.689	6.557	6.455	6.904
Mills/KWH w/o SNF	7.375	7.377	7.395	7.427	6.651	6.755	6.955	6.935	6.788	6.689	6.456	6.455	6.894

Indiana Michigan Power Company

Cook Unit 1 Monthly Expensing

2020

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Fuel Expense													
Net Generation (GWhT)	2335.3	2184.6	2335.3	2259.9	2335.3	2259.9	2335.3	2335.3	1657.3	678.0	2259.9	2335.3	25311.3
Conv. Factor (BTU/Kwh)	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	
Generation (MBTU)	7,968,259	7,454,177	7,968,259	7,711,218	7,968,259	7,711,218	7,968,259	7,968,259	5,654,893	2,313,365	7,711,218	7,968,259	86,365,642
BTU Charge ($/MBTU)	0.6175	0.6175	0.6175	0.6175	0.6175	0.6175	0.6175	0.6175	0.6175	0.6175	0.5571	0.5571	
Fuel Expense	$ 4,920,459	$ 4,603,010	$ 4,920,459	$ 4,761,735	$ 4,920,459	$ 4,761,735	$ 4,920,459	$ 4,920,459	$ 3,491,939	$ 1,428,520	$ 4,296,121	$ 4,439,325	$ 52,384,682
Monthly Expenses													
Fuel Expense	$ 4,920,459	$ 4,603,010	$ 4,920,459	$ 4,761,735	$ 4,920,459	$ 4,761,735	$ 4,920,459	$ 4,920,459	$ 3,491,939	$ 1,428,520	$ 4,296,121	$ 4,439,325	$ 52,384,682
Post '83 SNF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 75,000	$ -	$ 75,000
Fuel Reload Engineering	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 300,000
Total Monthly Expense	$ 4,945,459	$ 4,628,010	$ 4,945,459	$ 4,786,735	$ 4,945,459	$ 4,786,735	$ 4,945,459	$ 4,945,459	$ 3,516,939	$ 1,453,520	$ 4,396,121	$ 4,464,325	$ 52,759,682
Total Monthly Expense w/o SNF	$ 4,945,459	$ 4,628,010	$ 4,945,459	$ 4,786,735	$ 4,945,459	$ 4,786,735	$ 4,945,459	$ 4,945,459	$ 3,516,939	$ 1,453,520	$ 4,321,121	$ 4,464,325	$ 52,684,682
Generation (GWhE)	766.171	716.741	766.171	741.456	743.554	708.624	711.041	713.161	517.150	214.639	741.456	766.171	8,106.335
Mills/KWH	6.455	6.457	6.455	6.456	6.651	6.755	6.955	6.935	6.801	6.772	5.929	5.827	6.508
Mills/KWH w/o SNF	6.455	6.457	6.455	6.456	6.651	6.755	6.955	6.935	6.801	6.772	5.828	5.827	6.499

Indiana Michigan Power Company

Cook Unit 1 Monthly Expensing

2021

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Fuel Expense													
Net Generation (GWhT)	2335.3	2109.3	2335.3	2259.9	2335.3	2259.9	2335.3	2335.3	2259.9	2335.3	2259.9	2335.3	27495.9
Conv. Factor (BTU/Kwh)	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	
Generation (MBTU)	7,968,259	7,197,137	7,968,259	7,711,218	7,968,259	7,711,218	7,968,259	7,968,259	7,711,218	7,968,259	7,711,218	7,968,259	93,819,819
BTU Charge ($/MBTU)	0.5571	0.5571	0.5571	0.5571	0.5571	0.5571	0.5571	0.5571	0.5571	0.5571	0.5571	0.5571	
Fuel Expense	$ 4,439,325	$ 4,009,713	$ 4,439,325	$ 4,296,121	$ 4,439,325	$ 4,296,121	$ 4,439,325	$ 4,439,325	$ 4,296,121	$ 4,439,325	$ 4,296,121	$ 4,439,325	$ 52,269,469
Monthly Expenses													
Fuel Expense	$ 4,439,325	$ 4,009,713	$ 4,439,325	$ 4,296,121	$ 4,439,325	$ 4,296,121	$ 4,439,325	$ 4,439,325	$ 4,296,121	$ 4,439,325	$ 4,296,121	$ 4,439,325	$ 52,269,469
Post '83 SNF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 75,000	$ -	$ 75,000
Fuel Reload Engineering	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 300,000
Total Monthly Expense	$ 4,464,325	$ 4,034,713	$ 4,464,325	$ 4,321,121	$ 4,464,325	$ 4,321,121	$ 4,464,325	$ 4,464,325	$ 4,321,121	$ 4,464,325	$ 4,396,121	$ 4,464,325	$ 52,644,469
Total Monthly Expense w/o SNF	$ 4,464,325	$ 4,034,713	$ 4,464,325	$ 4,321,121	$ 4,464,325	$ 4,321,121	$ 4,464,325	$ 4,464,325	$ 4,321,121	$ 4,464,325	$ 4,321,121	$ 4,464,325	$ 52,569,469
Generation (GWhE)	766.171	692.026	766.171	741.456	743.554	708.624	711.041	713.161	705.204	739.313	741.456	766.171	8,794.348
Mills/KWH	5.827	5.830	5.827	5.828	6.004	6.098	6.279	6.260	6.127	6.038	5.929	5.827	5.986
Mills/KWH w/o SNF	5.827	5.830	5.827	5.828	6.004	6.098	6.279	6.260	6.127	6.038	5.828	5.827	5.978

Indiana Michigan Power Company

Cook Unit 2 Monthly Expensing

2017

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Fuel Expense													
Net Generation (GWhT)	2,451.2	2,214.0	2,451.2	2,372.1	2,451.2	2,372.1	2,451.2	2,451.2	2,372.1	2,451.2	2,372.1	2,451.2	28,860.7
Conv. Factor (BTU/Kwh)	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	
Generation (MBTU)	8,363,778	7,554,380	8,363,778	8,093,978	8,363,778	8,093,978	8,363,778	8,363,778	8,093,978	8,363,778	8,093,978	8,363,778	98,476,735
BTU Charge ($/MBTU)	0.7708	0.7708	0.7708	0.7708	0.7708	0.7708	0.7708	0.7708	0.7708	0.7708	0.7708	0.7708	
Fuel Expense	$ 6,446,741	$ 5,822,863	$ 6,446,741	$ 6,238,781	$ 6,446,741	$ 6,238,781	$ 6,446,741	$ 6,446,741	$ 6,238,781	$ 6,446,741	$ 6,238,781	$ 6,446,741	$ 75,905,173
Monthly Expenses													
Fuel Expense	$ 6,446,741	$ 5,822,863	$ 6,446,741	$ 6,238,781	$ 6,446,741	$ 6,238,781	$ 6,446,741	$ 6,446,741	$ 6,238,781	$ 6,446,741	$ 6,238,781	$ 6,446,741	$ 75,905,173
Post '83 SNF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 75,000	$ -	$ 75,000
Fuel Reload Engineering	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 300,000
Batch 23 Lease Interest	$ 7,753	$ 7,289	$ 6,825	$ 6,406	$ 5,942	$ 5,493	$ 5,029	$ 4,581	$ 4,117	$ 3,653	$ 2,304	$ 2,740	$ 62,132
Batch 24 Lease Interest	$ 36,203	$ 34,183	$ 29,051	$ 30,210	$ 27,281	$ 26,237	$ 23,436	$ 22,198	$ 20,309	$ 17,700	$ 16,336	$ 13,855	$ 296,998
Total Monthly Expense	$ 6,515,696	$ 5,889,335	$ 6,507,617	$ 6,300,397	$ 6,504,964	$ 6,295,511	$ 6,500,206	$ 6,498,519	$ 6,288,207	$ 6,493,093	$ 6,357,421	$ 6,488,335	$ 76,639,304
Total Monthly Expense w/o SNF	$ 6,515,696	$ 5,889,335	$ 6,507,617	$ 6,300,397	$ 6,504,964	$ 6,295,511	$ 6,500,206	$ 6,498,519	$ 6,288,207	$ 6,493,093	$ 6,282,421	$ 6,488,335	$ 76,564,304
Generation (GWhE)	822.715	743.098	822.715	796.176	814.234	785.232	811.406	811.406	774.288	817.768	796.176	822.715	9,617.929
Mills/KWH	7.920	7.925	7.910	7.913	7.989	8.017	8.011	8.009	8.121	7.940	7.985	7.886	7.968
Mills/KWH w/o SNF	7.920	7.925	7.910	7.913	7.989	8.017	8.011	8.009	8.121	7.940	7.891	7.886	7.961

Indiana Michigan Power Company

Cook Unit 2 Monthly Expensing

2018

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Fuel Expense													
Net Generation (GWhT)	2,451.2	2,214.0	2,451.2	237.2	2,214.0	2,372.1	2,451.2	2,451.2	2,372.1	2,451.2	2,372.1	2,451.2	26,488.6
Conv. Factor (BTU/Kwh)	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	
Generation (MBTU)	8,363,778	7,554,380	8,363,778	809,398	7,554,380	8,093,978	8,363,778	8,363,778	8,093,978	8,363,778	8,093,978	8,363,778	90,382,757
BTU Charge ($/MBTU)	0.7708	0.7708	0.7708	0.6008	0.6008	0.6008	0.6008	0.6008	0.6008	0.6008	0.6008	0.6008	
Fuel Expense	$ 6,446,741	$ 5,822,863	$ 6,446,741	$ 486,301	$ 4,538,813	$ 4,863,014	$ 5,025,115	$ 5,025,115	$ 4,863,014	$ 5,025,115	$ 4,863,014	$ 5,025,115	$ 58,430,960
Monthly Expenses													
Fuel Expense	$ 6,446,741	$ 5,822,863	$ 6,446,741	$ 486,301	$ 4,538,813	$ 4,863,014	$ 5,025,115	$ 5,025,115	$ 4,863,014	$ 5,025,115	$ 4,863,014	$ 5,025,115	$ 58,430,960
Post '83 SNF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 75,000	$ -	$ 75,000
Fuel Reload Engineering	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 300,000
Batch 23 Lease Interest	$ 2,291	$ 1,827	$ 2,737										$ 6,855
Batch 24 Lease Interest	$ 12,362	$ 10,343	$ 7,518	$ 6,370	$ 6,117	$ 6,140	$ 5,580	$ 5,392	$ 5,055	$ 4,530	$ 4,319	$ 3,818	$ 77,544
Total Monthly Expense	$ 6,486,394	$ 5,860,033	$ 6,481,996	$ 517,671	$ 4,569,931	$ 4,894,155	$ 5,055,695	$ 5,055,507	$ 4,893,069	$ 5,054,644	$ 4,967,333	$ 5,053,932	$ 58,890,359
Total Monthly Expense w/o SNF	$ 6,486,394	$ 5,860,033	$ 6,481,996	$ 517,671	$ 4,569,931	$ 4,894,155	$ 5,055,695	$ 5,055,507	$ 4,893,069	$ 5,054,644	$ 4,892,333	$ 5,053,932	$ 58,815,359
Generation (GWhE)	822.715	743.098	822.715	79.618	735.437	785.232	811.406	811.406	774.288	817.768	796.176	822.715	8,822.574
Mills/KWH	7.884	7.886	7.879	6.502	6.214	6.233	6.231	6.231	6.319	6.181	6.239	6.143	6.675
Mills/KWH w/o SNF	7.884	7.886	7.879	6.502	6.214	6.233	6.231	6.231	6.319	6.181	6.145	6.143	6.666

Indiana Michigan Power Company

Cook Unit 2 Monthly Expensing

2019

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Fuel Expense													
Net Generation (GWhT)	2,451.2	2,214.0	2,451.2	2,372.1	2,451.2	2,372.1	2,451.2	2,451.2	2,372.1	79.1	2,134.9	2,451.2	26,251.4
Conv. Factor (BTU/Kwh)	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	
Generation (MBTU)	8,363,778	7,554,380	8,363,778	8,093,978	8,363,778	8,093,978	8,363,778	8,363,778	8,093,978	269,799	7,284,580	8,363,778	89,573,359
BTU Charge ($/MBTU)	0.6008	0.6008	0.6008	0.6008	0.6008	0.6008	0.6008	0.6008	0.6008	0.6008	0.5299	0.5299	
Fuel Expense	$ 5,025,115	$ 4,538,813	$ 5,025,115	$ 4,863,014	$ 5,025,115	$ 4,863,014	$ 5,025,115	$ 5,025,115	$ 4,863,014	$ 162,100	$ 3,859,797	$ 4,431,619	$ 52,706,946
Monthly Expenses													
Fuel Expense	$ 5,025,115	$ 4,538,813	$ 5,025,115	$ 4,863,014	$ 5,025,115	$ 4,863,014	$ 5,025,115	$ 5,025,115	$ 4,863,014	$ 162,100	$ 3,859,797	$ 4,431,619	$ 52,706,946
Post '83 SNF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 75,000	$ -	$ 75,000
Fuel Reload Engineering	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 300,000
Batch 24 Lease Interest	$ 3,583	$ 3,209	$ 2,561	$ 2,473	$ 2,031	$ 1,737	$ 1,319	$ 989	$ 651	$ 315			$ 18,869
Total Monthly Expense	$ 5,053,698	$ 4,567,022	$ 5,052,675	$ 4,890,487	$ 5,052,146	$ 4,889,751	$ 5,051,434	$ 5,051,104	$ 4,888,666	$ 187,416	$ 3,959,797	$ 4,456,619	$ 53,100,815
Total Monthly Expense w/o SNF	$ 5,053,698	$ 4,567,022	$ 5,052,675	$ 4,890,487	$ 5,052,146	$ 4,889,751	$ 5,051,434	$ 5,051,104	$ 4,888,666	$ 187,416	$ 3,884,797	$ 4,456,619	$ 53,025,815
Generation (GWhE)	822.715	743.098	822.715	796.176	814.234	785.232	811.406	811.406	774.288	26.380	716.558	822.715	8,746.924
Mills/KWH	6.143	6.146	6.141	6.142	6.205	6.227	6.226	6.225	6.314	7.105	5.526	5.417	6.071
Mills/KWH w/o SNF	6.143	6.146	6.141	6.142	6.205	6.227	6.226	6.225	6.314	7.105	5.421	5.417	6.062

Indiana Michigan Power Company

Cook Unit 2 Monthly Expensing

2020

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Fuel Expense													
Net Generation (GWhT)	2,451.2	2,293.0	2,451.2	2,372.1	2,451.2	2,372.1	2,451.2	2,451.2	2,372.1	2,451.2	2,372.1	2,451.2	28,939.8
Conv. Factor (BTU/Kwh)	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	
Generation (MBTU)	8,363,778	7,824,179	8,363,778	8,093,978	8,363,778	8,093,978	8,363,778	8,363,778	8,093,978	8,363,778	8,093,978	8,363,778	98,746,535
BTU Charge ($/MBTU)	0.5299	0.5299	0.5299	0.5299	0.5299	0.5299	0.5299	0.5299	0.5299	0.5299	0.5299	0.5299	
Fuel Expense	$ 4,431,619	$ 4,145,708	$ 4,431,619	$ 4,288,664	$ 4,431,619	$ 4,288,664	$ 4,431,619	$ 4,431,619	$ 4,288,664	$ 4,431,619	$ 4,288,664	$ 4,431,619	$ 52,321,698
Monthly Expenses													
Fuel Expense	$ 4,431,619	$ 4,145,708	$ 4,431,619	$ 4,288,664	$ 4,431,619	$ 4,288,664	$ 4,431,619	$ 4,431,619	$ 4,288,664	$ 4,431,619	$ 4,288,664	$ 4,431,619	$ 52,321,698
Post '83 SNF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 75,000	$ -	$ 75,000
Fuel Reload Engineering	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 300,000
Total Monthly Expense	$ 4,456,619	$ 4,170,708	$ 4,456,619	$ 4,313,664	$ 4,456,619	$ 4,313,664	$ 4,456,619	$ 4,456,619	$ 4,313,664	$ 4,456,619	$ 4,388,664	$ 4,456,619	$ 52,696,698
Total Monthly Expense w/o SNF	$ 4,456,619	$ 4,170,708	$ 4,456,619	$ 4,313,664	$ 4,456,619	$ 4,313,664	$ 4,456,619	$ 4,456,619	$ 4,313,664	$ 4,456,619	$ 4,313,664	$ 4,456,619	$ 52,621,698
Generation (GWhE)	822.715	769.637	822.715	796.176	814.234	785.232	811.406	811.406	774.288	817.768	796.176	822.715	9,644.468
Mills/KWH	5.417	5.419	5.417	5.418	5.473	5.493	5.492	5.492	5.571	5.450	5.512	5.417	5.464
Mills/KWH w/o SNF	5.417	5.419	5.417	5.418	5.473	5.493	5.492	5.492	5.571	5.450	5.418	5.417	5.456

Indiana Michigan Power Company

Cook Unit 2 Monthly Expensing

2021

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Fuel Expense													
Net Generation (GWhT)	2,451.2	2,214.0	1,818.6	632.6	2,451.2	2,372.1	2,451.2	2,451.2	2,372.1	2,451.2	2,372.1	2,451.2	26,488.6
Conv. Factor (BTU/Kwh)	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	
Generation (MBTU)	8,363,778	7,554,380	6,205,383	2,158,394	8,363,778	8,093,978	8,363,778	8,363,778	8,093,978	8,363,778	8,093,978	8,363,778	90,382,757
BTU Charge ($/MBTU)	0.5299	0.5299	0.5299	0.5299	0.5414	0.5414	0.5414	0.5414	0.5414	0.5414	0.5414	0.5414	
Fuel Expense	$ 4,431,619	$ 4,002,753	$ 3,287,976	$ 1,143,644	$ 4,528,331	$ 4,382,256	$ 4,528,331	$ 4,528,331	$ 4,382,256	$ 4,528,331	$ 4,382,256	$ 4,528,331	$ 48,654,413
Monthly Expenses													
Fuel Expense	$ 4,431,619	$ 4,002,753	$ 3,287,976	$ 1,143,644	$ 4,528,331	$ 4,382,256	$ 4,528,331	$ 4,528,331	$ 4,382,256	$ 4,528,331	$ 4,382,256	$ 4,528,331	$ 48,654,413
Post '83 SNF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 75,000	$ -	$ 75,000
Fuel Reload Engineering	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 300,000
Total Monthly Expense	$ 4,456,619	$ 4,027,753	$ 3,312,976	$ 1,168,644	$ 4,553,331	$ 4,407,256	$ 4,553,331	$ 4,553,331	$ 4,407,256	$ 4,553,331	$ 4,482,256	$ 4,553,331	$ 49,029,413
Total Monthly Expense w/o SNF	$ 4,456,619	$ 4,027,753	$ 3,312,976	$ 1,168,644	$ 4,553,331	$ 4,407,256	$ 4,553,331	$ 4,553,331	$ 4,407,256	$ 4,553,331	$ 4,407,256	$ 4,553,331	$ 48,954,413
Generation (GWhE)	822.715	743.098	610.402	212.314	814.234	785.232	811.406	811.406	774.288	817.768	796.176	822.715	8,821.753
Mills/KWH	5.417	5.420	5.428	5.504	5.592	5.613	5.612	5.612	5.692	5.568	5.630	5.535	5.558
Mills/KWH w/o SNF	5.417	5.420	5.428	5.504	5.592	5.613	5.612	5.612	5.692	5.568	5.536	5.535	5.549

DIRECT TESTIMONY OF CHARLES F. WEST
ON BEHALF OF
INDIANA MICHIGAN POWER COMPANY
2017 PSCR PLAN CASE

Q. Please state your name, position, and business address.

A. My name is Charles F. West. My position is Manager, Coal Procurement, in the regulated Commercial Operations organization of American Electric Power Service Corporation (AEPSC), a subsidiary of American Electric Power Company, Inc. (AEP). My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. What are your primary areas of responsibility as Manager, Coal Procurement, for AEPSC?

A. I am responsible for managing coal procurement, contract oversight, and inventory management activities for AEP operating companies, including Indiana Michigan Power Company (I&M), Kentucky Power Company (KPCo), Southwestern Electric Power Company (SWEPCO), Public Service Company of Oklahoma (PSO), Appalachian Power Company (APCo) and, as an agent for Ohio Valley Electric Corporation and Indiana-Kentucky Electric Corporation.

Q. Please briefly describe your educational background.

A. I graduated from Queen's University in Kingston, Ontario, Canada in 1978 with a degree in Mining Engineering and I later obtained my Professional Engineer license in the State of Washington.

Q. Please describe your professional background.

A. After graduation in 1978, I was employed in the mining industry by Cleveland Cliffs Iron Company in Michigan and later by Quintette Coal

Company in British Columbia. I then spent over seven years employed by PacifiCorp in various engineering and management positions at coal mining operations in Washington state and Wyoming and at their headquarters in Salt Lake City, Utah. In 1995, I accepted a position as Coal Buyer for Central and Southwest Corporation (CSW), a utility holding company in Dallas, Texas. I transferred to Columbus, Ohio as a Coal Buyer after CSW's merger with AEP in 2000. In 2003, I joined Reliant Energy Inc. in Canonsburg, PA as a Senior Fuels Specialist. In 2005, I returned to AEP as a Coordinator in the Fuels, Emissions and Logistics (FEL) department. I was promoted to Manager of Cook Coal Terminal in Metropolis, IL in 2007 and accepted my current position in FEL in January of 2009. Beginning in 2014, the FEL organization and the Commercial Operations employees were consolidated to become the regulated Commercial Operations organization.

Q. Have you previously filed testimony before this Commission or other Commissions?

A. Yes. I have submitted testimony to the Michigan Public Service Commission and the Indiana Utility Regulatory Commission on behalf of I&M, the Public Utility Commission of Texas on behalf of SWEPCO, and the Oklahoma Corporation Commission on behalf of PSO. I have also testified before the Kentucky Public Service Commission on behalf of KPCo, the Virginia State Corporation Commission on behalf of APCo, and the Public

Service Commission of West Virginia on behalf of APCo and Wheeling Power Company.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to:

(1) Provide a summary of I&M's long-term supply agreements;

(2) Submit a short-term forecast of delivered coal prices for the calendar year 2017;

(3) Submit a five-year forecast of projected delivered coal prices;

(4) Discuss I&M's coal purchasing strategy; and

(5) Discuss market conditions affecting I&M's fuel costs.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring two exhibits:

(1) Exhibit IM-12 (CFW-1) titled "Indiana Michigan Power Company Monthly Coal Cost Forecast," which provides a forecast of the monthly delivered coal costs for I&M's coal generating station in 2017; and

(2) Exhibit IM-13 (CFW-2) titled "Indiana Michigan Power Company Five Year Annual Coal Cost Forecast," which provides a forecast of annual delivered coal costs for I&M's generating station from 2017 through 2021.

Q. Please describe the role of AEPSC in I&M's fuel procurement process.

A. AEPSC, acting as agent for all of the electric utility operating companies of AEP System, including I&M, is responsible for the procurement and delivery of coal to the Company's generating stations, as well as establishing coal inventory target levels and managing those levels.

AEPSC's primary objective is to assure a continuous supply of coal of the appropriate quality to all of AEP's coal generating stations, delivered at the lowest reasonable cost over a period of years so as to promote the generation of the lowest cost per kWh of electricity, within the constraints of safety, reliability of supply, and environmental requirements.

Coal deliveries must be arranged so that sufficient coal is available to provide and maintain adequate and dependable electric service for the customer. The quality of the delivered coal, in addition to the consistency of the sulfur content, is fundamental to I&M achieving and maintaining compliance with the applicable environmental limitations and operating efficiencies.

Q. Please identify and describe I&M's coal generating station.

A. Located in Spencer County, Indiana, Rockport, I&M's sole coal generating station, consists of two 1300-megawatt coal generating units. Sulfur dioxide (SO_2) emissions at Rockport are limited by the New Source Performance Standard to 1.2 lbs. SO_2 per million British thermal unit (MMBtu). Compliance with the emission limit is achieved by using a blend consisting primarily of low-sulfur subbituminous coal in the steam generators. 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 U.S. Environmental Protection Agency (EPA) emissions standards, Dry Sorbent Injection (DSI) is being used at both Rockport units. The use of DSI technology has not resulted in a need to change the coal blend at Rockport.

Q. Please summarize the contracts forecasted to be used to supply coal in 2017.

A. The summary below contains information on the contracts under which I&M expects to receive coal during the calendar year 2017. The first column lists the suppliers represented by consecutive letters. A letter is used in lieu of a name in order to maintain the confidentiality of individual suppliers. The second column identifies the type of coal. While, western coal typically originates in the Power River Basin in Wyoming, eastern coal can originate from a variety of sources located in West Virginia or Kentucky. The third column represents the contractual start and end period (month and year). The fourth and final column displays the tons I&M expects to receive under each contract in 2017. Eastern coal can be received directly into the plant, while western coal is received at the Cook Coal Terminal and transloaded to barge for shipment to the plant when needed.

Supplier	Coal Type	Term	2017 Tons
A	Western	Jan 17 - Dec 17	2,000,000
B	Western	Dec 04 - Dec 17	1,000,000
C	Western	Jan 17 - Dec 17	500,000
D	Eastern	Jan 16 - Dec 17	90,000
E	Eastern	Jan 16 - Dec 17	70,000

Q. Please provide a summary of I&M's anticipated coal supplies and costs.

A. The majority of I&M's need for coal during 2017 will be supplied by a combination of short-term contracts and one long-term coal contract that has been in place for several years. In addition to the above mentioned contracts, coal may also be purchased to fulfill any additional supply requirements through spot agreements with various other suppliers. I&M expects to receive approximately 6.5 million tons of coal in 2017 at the Rockport plant at a projected weighted average delivered cost of 206.58 cents per MMBtu or $37.62 per ton (exclusive of affiliated transportation costs).

All of the forecasted deliveries and costs, as discussed above, are supported by Exhibit IM-13 (CFW-1) and were provided to Witness Heimberger for use in preparing I&M's forecast.

Q. How were the forecasted deliveries and prices determined?

A. The amount of coal projected to be consumed was based on load forecasts for the applicable years. Coal delivery requirements were then determined by taking into consideration coal inventory, the forecast of coal consumption, and adjustments for any contingencies that would necessitate an increase or decrease in coal inventory levels.

Next, the sources of the coal were determined by taking into account environmental and boiler constraints, as well as, contractual obligations and existing sources of supply. The price of contract coal and committed spot market purchases are based on contractual agreements. The prices of coal purchases not yet committed were estimated based on AEPSC's market knowledge.

Finally, transportation costs were forecasted based on an estimate of the rates under the rail contract with Union Pacific to deliver western coal to the Cook Coal Terminal that became effective on January 1, 2013.

Q. Please describe I&M's coal purchasing strategy.

A. I&M's coal purchasing strategy is based on continuous market monitoring and evaluation along with periodic competitive bids. After I&M's uncommitted needs for coal during the upcoming year are estimated, coal producers are contacted and given the parameters for the amount and quality of coal that is sought. From bid results and/or existing opportunities, if reasonable, I&M then makes its selection of the coals needed to meet its requirements based primarily on price and coal quality considerations.

Q. How are market conditions affecting I&M's coal costs?

A. The relatively cool summer of 2015, followed by the warm winter of 2015/2016, reduced the demand for and the corresponding price for natural gas to the point that Rockport was not being selected to generate in the PJM market. Although coal prices with respect to the NYMEX (New York Mercantile Exchange) and CSX[1] coal were depressed in 2015, this reduction in coal consumption continued to apply downward pressure on the market, which led to the closure of a significant portion of the Central Appalachian (CAPP) coal production in Kentucky and West Virginia. The cost of NYMEX

[1] CSX is the over-the-counter (OTC) broker index for coal loaded on CSX rail.

coal for Rockport remained moderately stable throughout the 2016 calendar year. While PRB coal pricing was relatively strong in the beginning of 2015, the market began experiencing the same downward pressure that other basins were experiencing throughout the year and into 2016. These downward pressures should result in a reduced, stable price for coal through 2017.

Q. How are recent changes in the coal industry impacting coal procurement for I&M?

A. While the coal industry continues to deal with bankruptcies as well as mergers and acquisitions, I&M continues receiving coal deliveries as contracted and expects to continue doing so into the future. The fuel procurement team monitors all coal industry news and will continue to consider a vendor’s financial situation when procuring coal.

Q. What is the status of the Mercury & Air Toxics Standards (MATS) and the Cross-State Air Pollution Rule (CSAPR) regulations, and what impact is expected on the forecasted cost of coal for I&M as a result of the regulations?

A. After significant litigation, on June 13, 2016, the Supreme Court denied a multiple-state request, led by the state of Michigan, to reconsider whether MATS should remain in effect while the authority of the EPA to issue the regulation is considered. Therefore, even if the court ultimately concludes that the EPA does not have the authority, MATS impact to the plants will have occurred and the closures and investments made to those plants to become compliant would then effectively be non-reversible.

In addition to the MATS Rule, the EPA, on July 6, 2011, released CSAPR. Under CSAPR, reductions in SO_2 and nitrogen oxide (NO_X) emissions were to begin as early as January 1, 2012. Due to extensive litigation, Phase I of CSAPR's annual SO_2 and NO_x reductions began on January 1, 2015. Phase I of CSAPR's seasonal ozone NO_x reductions went into effect on May 1, 2015. Phase II of CSAPR is scheduled to begin in 2017. On November 16, 2015, the EPA proposed the CSAPR Update Rule, which would reduce the NO_x emissions for 23 states under the CSAPR, including Indiana. These revisions to ozone season budgets are intended to address the required 2008 revisions to ozone National Ambient Air Quality Standards. AEP, on behalf of I&M and its other operating companies, filed comments to the proposed updates to CSAPR on February 1, 2016, identifying certain flaws with the EPA's proposal. At this time, I&M cannot reasonably determine what effect this new proposal will ultimately have, but the Company will continue to monitor this proposal and any anticipated impacts when it is practical to do so.

Both the MATS Rule and CSAPR continue to contribute to, or impact, the price differential for the ultra-low sulfur PRB (0.55 lbs. SO_2/MMBtu) coal that is offered into the market.

Q. Are you aware of any other factors that will impact the forecasted cost of coal for I&M?

A. No, I am not.

Q. Is risk assessment an important factor in I&M's coal purchasing decision?

A. Yes. The Company considers a vendor's financial status, ability to deliver, and past performance when evaluating its decision to do business with that supplier. Before a purchase is made, each operation submitting a coal proposal is evaluated by the coal procurement team to make an assessment of their ability to meet the obligations of the contract. Currently, the financial health of the coal industry is such that no major coal supplier can meet the credit requirements. Regardless of the poor financial condition of the industry, the Company's suppliers continue to meet their contractual obligations. With this in mind, the Company continues to evaluate the risk of each offer independently to ensure that any purchase made will serve to enhance I&M's security of supply.

Q. Do you have an opinion regarding the reasonableness of I&M's projected coal costs?

A. Yes. I&M has and continues to aggressively pursue and manage its coal supply and transportation costs to provide a reliable coal supplies at the lowest reasonable cost. In my opinion, the projected coal costs are reasonable.

Q. Does this conclude your direct testimony?

A. Yes.

Indiana Michigan Power Company
Monthly Coal Cost Forecast
For the Year 2017

	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Total
Rockport													
Tons (000)	513	563	566	451	447	457	652	650	437	647	563	651	6,598
¢/MMBTU	210.24	208.96	205.52	206.06	206.16	205.67	204.85	205.11	208.20	206.07	207.48	205.94	206.58

Slight variances due to rounding

Exhibit IM-13 (CFW-2)

Indiana Michigan Power Company
Five Year Annual Coal Cost Forecast
For the Years of 2017 Through 2021

	2017	2018	2019	2020	2021
Rockport					
Tons (000)	6,598	7,313	7,034	6,940	7,072
¢/MMBTU	206.58	214.13	222.31	222.10	240.16

Slight variances due to rounding

DIRECT TESTIMONY OF NANCY A. HEIMBERGER
ON BEHALF OF
INDIANA MICHIGAN POWER COMPANY
2017 PSCR PLAN CASE

Q. Would you please state your name and business address?

A. My name is Nancy A. Heimberger, and my business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. By whom are you employed and what is your position?

A. I am employed by American Electric Power Service Corporation (AEPSC) as a Financial Analyst Senior Staff in Corporate Planning and Budgeting. AEPSC supplies engineering, financing, accounting, and planning and advisory services to the subsidiaries of the American Electric Power System, one of which is Indiana Michigan Power Company (I&M or Company).

Q. Please describe your educational and professional background.

A. I earned a Bachelor of Business Administration Degree in Accounting from Ohio University in 1986. I am a Certified Public Accountant (Inactive) in the state of Ohio. I was first employed by Arthur Andersen & Co. in 1986 in the Audit section where I performed audits of financial statements and internal controls for various clients. From 1988 to 1997, I was employed by Columbia Energy Group, Inc. and held positions in the Internal Audit, Accounting, and Tax Departments. From 1997 to the present, I have been employed by AEPSC. I have held positions in the Tax, Regulated Pricing and Analysis, and Corporate Planning and Budgeting Departments.

Q. What are your responsibilities as a Financial Analyst Senior Staff?

A. I prepare and review financial forecasts and analyses for I&M, and perform quality control over the financial forecast and analysis processes for the AEP System's utility companies. In this role, I prepare and review short- and long-term forecasts for I&M, as well as monthly analyses of budget to actual variances. With respect to this filing, I am responsible for the derivation of the Power Supply Cost Recovery (PSCR) data for the forecast periods.

Q. Have you previously submitted testimony in any regulatory proceedings?

A. Yes, I have testified and/or submitted testimony before the Michigan Public Service Commission (Commission) on behalf of I&M in Case Numbers U-16801, U-17025, U-17032 and U-17919, the 2016 MPSCR plan and before the Indiana Utility Regulatory Commission on behalf of I&M in Cause Nos. 43827 DSM 3 & 4, 44422, 44182 LCM-4, 44331 ECR 1, 44555 and 38702-FAC75 through FAC77.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present the forecasts of the Company's monthly power supply costs and net energy requirements for the period January 2017 through December 2017 and, in accordance with Commission requirements, provide similar data on an annual basis for the years 2017 through 2021. I will also describe the methodologies employed to derive I&M's estimated power supply costs.

Q. Have the data you are sponsoring been prepared in a manner generally consistent with previous I&M PSCR Plan filings and modified for the Commission Orders in Case U-16433 and Case U-16801?

A. Yes. I have prepared data consistent with previous PSCR Plan filings, with the modifications from Commission Orders in Case U-16433 and Case U-16801 included.

Q. What exhibits are you sponsoring in this proceeding?

A. I am sponsoring the following exhibits:

- Exhibit IM-14 (NAH-1) that identifies, by component, the forecasted monthly Total Company - Michigan Basis power supply costs for the period January 1, 2017 through December 31, 2017.
- Exhibit IM-15 (NAH-2) that details the forecasted monthly Total Company - Michigan Basis net energy requirement for the period January 1, 2017 through December 31, 2017.
- Exhibit IM-16 (NAH-3) that identifies, by component, the annual forecasted Total Company - Michigan Basis power supply costs for the years 2017 through 2021.
- Exhibit IM-17 (NAH-4) that details the forecasted annual Total Company - Michigan Basis net energy requirement for the years 2017 through 2021.

Q. What are the power supply costs you address?

A. Power supply costs, as shown on Exhibits IM-14 (NAH-1) and IM-16 (NAH-3), reflect those costs allowable under the terms of I&M's PSCR clause adopted pursuant to Act 304 of the Public Acts of 1982, and the methodologies in this PSCR Plan are consistent with the PSCR basing point included in the Commission Order in Case U-16801.

The costs included in the determination of the total power supply cost include all items in accounts 447 and 555 except those related to Indiana jurisdictional trackers and revenues directly related to I&M’s wholesale requirements customers. There are also a few items that are not in accounts 447 and 555 that are related to Off-System Sales (OSS) margins that have been included in the development of I&M's Total Company - Michigan Basis PSCR factor.

Q. Please identify the 447 and 555 accounts that have been excluded in the development of I&M's Total Company - Michigan Basis PSCR factor.

A. The 447 and 555 accounts related to Michigan’s Renewable Energy Surcharge, Indiana’s jurisdictional trackers and revenues directly related to I&M’s wholesale requirements customers that have been excluded in the development of I&M's Total Company - Michigan Basis PSCR factor are provided in the following table:

Account	Description
4470027	Wholesale/Municipal/Public Authority Fuel Revenue
4470033	Wholesale/Municipal/Public Authority Base Revenue
4470150	Trans Revenue - Dedicated Wholesale/Municipal
4470171	Over-Under OSS Margin Sharing – Indiana
4470172	Over-recovered PJM Expense – Indiana
4470183	Over-recovered Capacity - IN
5550106	Under-recovered PJM Expense – Indiana
5550119	Under-recovered Capacity - IN
5550145	Defrd RES Wildcat Wind Cost-MI

Q. Would you please provide a general description of the methodologies and assumptions utilized in the development of I&M's Total Company - Michigan Basis PSCR costs for the period 2017 through 2021?

A. A discussion of the specific methodologies and assumptions used in the derivation of each of these items by category follows.

<u>Fossil Fuel Expense</u>

Q. Would you please describe how the cost of fossil fuel consumed was calculated?

A. Yes. The cost of fossil fuel consumed was based on the generation forecast for each of I&M's fossil generating units as projected by the AEPSC's Resource Planning Section and provided to me by Witness Baker, and on the projection of fossil fuel deliveries and costs as developed by the regulated Commercial Operations organization and provided to me by Witness West.

The cost of fossil fuel consumed for each of I&M's generating units is equal to the number of tons of coal consumed multiplied by the average unit cost of coal in fuel inventory ($/ton), Account 151.

For the 2017 plan year, the cost of fuel consumed was developed on a monthly basis. The average cost of coal was defined as the weighting of the average cost of coal in inventory at the beginning of the month plus the projected cost of fuel delivered during the month. The tons of coal consumed were calculated by Witness Baker using the *PLEXOS*® production cost simulation model.

Exhibit IM-14 (NAH-1), line 2 includes fuel handling costs and ash disposal costs net of ash sales proceeds which are then credited (as shown on Exhibit IM-14 (NAH-1), lines 24 and 26) against the total power supply cost. Exhibit IM-14 (NAH-1), line 2 also includes affiliated transportation costs which are subject to base rate recovery. As such, these costs are also credited against the total power supply cost as shown on Exhibit IM-14 (NAH-1), line 25.

Nuclear Fuel Expense

Q. Would you please describe how the projection of nuclear fuel expense was developed?

A. Yes. Nuclear fuel expense was forecasted for each unit of the Donald C. Cook Nuclear Plant. The projection of nuclear fuel expense consists of a base fuel component and post-April 7, 1983 spent nuclear fuel disposal costs. The base fuel component was calculated by multiplying the number of British thermal units (BTU's) generated by the nuclear fuel by the BTU charge. Lease finance and administrative charges are then added to this amount. Post-April 7, 1983 spent nuclear fuel disposal costs are calculated based on the rate of one mill per kilowatt-hour of electricity generated and sold in accordance with the Nuclear Waste Policy Act of 1982. However, the Department of Energy provided notice that effective May 16, 2014, the Spent Nuclear Fuel Disposal Fee will be 0.0 mill per kWh of electricity generated and sold. The projections of nuclear generation and nuclear fuel expense were provided to me by Witness Bellville.

Solar Fuel Expense

Q. Would you please describe how the Solar Generation cost includable in the PSCR was determined?

A. Yes. The solar generation costs includable in the PSCR are based on the projected solar generation and the transfer rate from the 2015 transfer schedule created by Staff in Case U-15800 and approved in I&M's Renewable Energy Plan in Case U-17794.

Allowance Consumption and Allowance Gains/(Losses)

Q. How does the Company calculate allowance consumption expense?

A. I&M is required to hold sufficient emission allowances to meet compliance with Title IV of the Clean Air Act Amendments and the USEPA's Cross-State Air Pollution Rule (CSAPR). The Company expenses allowances based on the weighted average inventory (WAI) price of allowances held in current inventory for each allowance vintage based on its allowances-per-ton-emitted surrender ratio (1:1). WAI price is the total dollar balance of current inventory divided by the number of allowances held. For Title IV SO2, the inventory balance includes zero cost allowances received from the EPA, allowances purchased from affiliates through the former Interim Allowance Agreement (IAA) and allowances purchased from non-affiliates. For CSAPR NOx and SO2 allowances, the inventory is composed of zero cost allowances received from the EPA and purchased allowances. Allowance expenses are shown on Exhibit IM-14 (NAH-1), line 9.

Q. How does the Company calculate allowance gains/losses?

A. Allowance gains/losses are determined by subtracting the inventory cost of sales from allowance sales proceeds. For the plan year 2017, I&M is expecting to recognize slight gains from the sale of excess CSAPR NOx and SO2 allowances. Allowance gains/losses are shown on Exhibit IM-14 (NAH-1), line 23.

Consumables

Q. For what purposes does I&M use consumables?

A. I&M currently consumes both activated carbon and sodium bicarbonate at its Rockport Plant. Activated carbon is injected into the flue gas stream to reduce mercury emissions, and sodium bicarbonate is used with dry sorbent injection equipment to reduce SO_2 emissions.

Selective Catalytic Reduction (SCR) equipment is forecasted to be installed at Rockport Unit 1 in 2017 and Rockport Unit 2 in 2019. This equipment will use anhydrous ammonia in a process designed to reduce NOx emissions.

Q. What costs are included in I&M's 2017 PSCR Plan as a result of using these consumables?

A. I&M's 2017 PSCR forecast includes expenses associated with the consumption of activated carbon and sodium bicarbonate at Rockport Plant. Beginning in 2018, the forecast also includes expenses associated with the consumption of anhydrous ammonia in conjunction with the SCR equipment. Consumable expenses are shown on Exhibit IM-14 (NAH-1), line 10, and Exhibit IM-16 (NAH-3), line 10.

Purchased Power

Q. Referring to Exhibit IM-14 (NAH-1), what costs are reflected in lines 11-14 associated with Purchased Power?

A. Purchased Power includes the costs of planned and unplanned non-affiliated purchases, planned wind purchases, and planned purchases from the AEP Generating Company (AEG). Also included are other solar power purchases beginning in 2020.

Q. Would you please describe the non-affiliated purchases?

A. Yes. Non-affiliated purchases include planned purchases from the Ohio Valley Electric Corporation (OVEC) as well as I&M's unplanned market purchases it occasionally will make from non-affiliated suppliers to meet its total load.

Q. How were the costs associated with the non-affiliated purchases

determined?

A. The projected gigawatt-hours (GWh) purchased from OVEC reflect I&M's share of the anticipated OVEC surplus. The cost associated with these purchases is based on a contractual agreement with OVEC.

For 2017, the costs associated with other non-affiliated purchases were based on I&M’s stand-alone projected unplanned energy purchases that I&M occasionally would be expected to make from non-affiliated suppliers.

Q. Do the projected 2017 PSCR costs include Wind Purchases?

A. Yes. The total cost of I&M’s wind power purchases are included in the 2017 forecast of PSCR costs, as shown on Exhibit IM-14 (NAH-1), line 12. The total cost includes purchases from the Fowler Ridge, Wildcat and Headwaters wind farms. Also included are other wind power purchases beginning in 2020. Purchases from Fowler Ridge are included pursuant to the MPSC Order in Case U-15361, dated December 4, 2007 and the MPSC Order in Case U-15808, dated September 15, 2009. Wildcat purchases are included pursuant to the MPSC Order in Case U-16584, dated August 25, 2011. Headwaters purchases are included pursuant to the MPSC Order in Case U-17375, dated March 6, 2014.

Q. Would you please describe the purchases from AEG?

A. Planned purchases from AEG represent the purchase of 70% of the power and energy from AEG's share of Rockport Units 1 & 2. The costs associated with these purchases are composed of both fuel and non-fuel charges.

Q. Would you please explain the derivation of the non-fuel charges associated with the Rockport Unit's 1 and 2 unit power purchases from AEG?

A. Yes. Pursuant to the Unit Power Agreement between I&M and AEG (FERC Rate Schedule No. 1), as amended, I&M agrees to pay AEG, in consideration for the right to receive a portion of the output from AEG's share of Rockport Units 1 & 2, an amount sufficient to enable AEG to pay its operating and other expenses, as well as to provide a return on its investment. The projection of the non-fuel charges for the 2017 plan year was calculated based upon the terms of the Unit Power Agreement, approved by the FERC on August 1, 1984, and reflects I&M's purchase of 70% of the power to which AEG is entitled from Rockport Unit's 1 and 2 (which is equivalent to 35% of the total power from both units).

PJM Interconnection LLC (PJM) Ancillaries

Q. Would you please identify the items included in PJM Ancillaries that result from the AEP East System's participation in the PJM Regional Transmission Organization?

A. Yes. PJM Ancillaries include operating reserve charges and credits as well as charges and credits for ancillary services. In the 2017 PSCR Plan forecast, these charges and credits are directly assigned to I&M, as shown on Exhibit IM-14 (NAH-1), line 15.

Q. Can you provide a brief description of these services provided by PJM?

A. Yes, the following provides a brief description:

PJM Operating Reserves - Operating reserve charges cover the operating reserve credits provided as make-whole payments to generators that are called on by PJM out of economic dispatch order and do not receive sufficient revenues from the energy or ancillary service markets to cover their offers.

Ancillary Services - These charges and credits are associated with services that are necessary to support the transmission of capacity and energy from resources to loads, while maintaining reliable operation of the transmission system.

Financial Transmission Rights (FTR) Revenue, Net of Congestion Costs - Load Serving Entity (LSE)

Q. Would you please describe the FTR Revenue, Net of Congestion Costs - LSE that are included in Exhibit IM-14 (NAH-1), line 16?

A. Yes. Congestion costs in PJM are simply the difference between what a load pays for energy and what a generator supplying the load receives for the energy it produces. If there were no congestion on any transmission line in PJM, the Locational Marginal Price (LMP) would be the same for all generators and loads across the entire PJM market region (not taking marginal losses into account). However, when transmission lines become constrained, LMPs vary across the entire region and the price for energy paid by the load is different than the price received for energy produced by the generator.

To offset this impact, LSEs and integrated utilities such as AEP are assigned auction revenue rights (ARRs) which can be converted into FTRs through PJM's FTR auctions. ARRs are an entitlement to receive an allocation of net FTR auction revenues and provide for a fixed stream of revenues based on the results of the FTR auctions. FTRs are financial instruments that entitle the holder to the right to receive compensation from PJM for congestion on the FTR's path. All FTRs have a source point (beginning) and a sink point (end). The difference between the day-ahead FTR sink and source congestion components of LMP determines the value of each FTR path. Since the value of FTRs are based upon the congestion components of LMP, their value will rise and fall with congestion prices and therefore provide for a variable revenue stream that should track increases and decreases in congestion costs. The purpose of ARRs and FTRs is to help these load-serving customers mitigate the incremental costs associated with congestion by effectively offering the LSE a financial hedge to offset the uncertainty associated with such congestion impacts on LMPs.

Transmission Losses

Q. Would you please describe the Transmission Losses that are included in Exhibit IM-14 (NAH-1), line 17?

A. Yes. These costs and credits are associated with the financial settlement of transmission line losses due to resistance on the transmission system within PJM.

<u>OSS Revenue Cost of Goods Sold (COGS)</u>

Q. Referring to Exhibit IM-14 (NAH-1), line 21, would you please describe the credits associated with OSS Revenue COGS?

A. Yes. OSS Revenue COGS is the cost recovery portion of OSS revenue. Specifically, revenues related to known or committed system sales were developed in accordance with the terms of the specific existing agreements governing those known system sales. Since uncommitted system sales as described by Witness Baker are primarily short-term in nature and are representative of spot market energy sales in PJM, the prices and the ultimate counter-party buyers from PJM are not known or knowable. As a result, the forecast of revenues from such uncommitted system sales was based on the recovery of the AEP production costs of making those wholesale energy sales along with a forecast of net realizations (revenues less out-of-pocket costs) based on expected (PJM) market conditions at the AEP-Dayton market hub.

The revenue shown on Exhibit IM-14 (NAH-1), line 21 recovers the variable cost of making the off-system sales. It includes the variable generating costs of fuel, fuel handling, one-half of maintenance costs, and emission allowance costs or the purchases associated with making these sales. Such costs are forecasted for I&M, within PJM, on a stand-alone basis.

<u>OSS Margin (80%)</u>

Q. Referring to Exhibit IM-14 (NAH-1), line 22, would you please describe the credits associated with OSS Margin (80%)?

A. Yes. OSS Margin (80%) represents the customers' portion of I&M's margins received from OSS. The OSS Margins are derived from physical operations (which are calculated by subtracting the variable cost of making OSS as described above from the related revenue) and financial transactions. This sharing of 80% of OSS margins was the level agreed to in the settlement of Case No. U-16801 approved by the Commission.

<u>Adjustment for Fuel Handling and Affiliated Transportation Exclusion</u>

Q. Have you excluded fuel handling and affiliated transportation costs in the determination of the Total Company - Michigan Basis power supply cost?

A. Yes. Consistent with Act 304, I have excluded $5,835,000 in fuel handling costs and $14,510,000 in affiliated transportation costs.

<u>Adjustment for Ash Disposal Costs/Credits</u>

Q. Have you excluded ash disposal costs/credits in the determination of the Total Company - Michigan Basis power supply cost?

A. Yes. Consistent with the Commission's Order in I&M's 2011 PSCR Plan, Case U-16433, which rejected the Company's proposal to include ash disposal costs and revenues in I&M's PSCR Clause as currently defined, I have excluded $2,121,000 in net ash disposal costs/credits.

<u>Total Company- Michigan Basis Projected 2017</u>

<u>Power Supply Costs and Net Energy Requirements</u>

Q. What are I&M's projected 2017 power supply costs and net energy

requirements?

A. The 2017 power supply costs for I&M, on a total Company basis, are estimated to be $469,647,000 or 19.37 mills per kWh before consideration for any line losses, based on a net energy requirement of 24,234.9 GWh.

Q. Does this conclude your testimony?

A. Yes.

Exhibit IM-14 (NAH-1)

INDIANA MICHIGAN POWER COMPANY
2017-2021 MICHIGAN PSCR PLAN
TOTAL COMPANY - MICHIGAN BASIS
($000)

Line No.	Description	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	2017 Total
1	**Fuel Costs**													
2	Fossil Generation	$ 19,550	$ 18,652	$ 11,040	$ 8,362	$ 6,294	$ 13,082	$ 15,717	$ 14,237	$ 10,511	$ 12,998	$ 11,982	$ 17,130	$ 159,556
3	Nuclear Generation	$ 12,514	$ 11,307	$ 12,498	$ 12,099	$ 12,489	$ 12,087	$ 12,483	$ 12,475	$ 9,965	$ 6,531	$ 6,677	$ 12,143	$ 133,268
4	Solar Generation	$ 76	$ 95	$ 153	$ 177	$ 208	$ 221	$ 219	$ 196	$ 166	$ 130	$ 72	$ 56	$ 1,770
5														
6	Total Fuel Cost	$ 32,141	$ 30,054	$ 23,690	$ 20,638	$ 18,992	$ 25,389	$ 28,419	$ 26,909	$ 20,642	$ 19,659	$ 18,731	$ 29,329	$ 294,593
7														
8	Plus:													
9	Allowance Consumption	$ 201	$ 193	$ 122	$ 90	$ 73	$ 168	$ 216	$ 221	$ 200	$ 144	$ 131	$ 191	$ 1,948
10	Consumables	$ 2,106	$ 2,031	$ 1,205	$ 913	$ 685	$ 1,411	$ 1,713	$ 1,545	$ 1,115	$ 1,396	$ 1,277	$ 1,858	$ 17,253
11	Purchased Power Non-Affil	$ 4,485	$ 4,313	$ 4,745	$ 3,522	$ 4,382	$ 4,755	$ 5,277	$ 5,738	$ 7,843	$ 9,806	$ 11,876	$ 4,192	$ 70,934
12	Purchased Power - Wind	$ 8,592	$ 7,308	$ 7,628	$ 7,610	$ 6,086	$ 4,313	$ 3,191	$ 2,526	$ 3,133	$ 6,662	$ 8,152	$ 8,012	$ 73,213
13	Purchased Power - Solar	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Purchased Power - AEG	$ 30,245	$ 25,883	$ 18,055	$ 16,535	$ 14,408	$ 21,690	$ 21,998	$ 20,251	$ 23,025	$ 18,899	$ 20,911	$ 23,539	$ 255,438
15	PJM Ancillaries	$ 788	$ 738	$ 688	$ 738	$ 638	$ 638	$ 688	$ 738	$ 638	$ 638	$ 738	$ 738	$ 8,406
16	FTR Revenue Net of Congestion Costs - LSE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
17	Transmission Losses	$ 1,400	$ 1,000	$ 500	$ 1,000	$ 500	$ 1,500	$ 1,300	$ 1,400	$ 1,000	$ 1,000	$ 500	$ 500	$ 11,600
18														
19														
20	Less:													
21	Off-System Sales Revenue COGS	$ 28,493	$ 28,027	$ 17,161	$ 15,643	$ 10,187	$ 16,277	$ 17,097	$ 15,983	$ 10,615	$ 8,220	$ 8,831	$ 26,863	$ 203,397
22	Off-System Sales Margin (80%)	$ 10,996	$ 9,793	$ 3,008	$ 633	$ (245)	$ 1,344	$ 3,033	$ 3,105	$ 501	$ (174)	$ 173	$ 5,663	$ 37,829
23	Allowance Gains/(Losses)	$ 5	$ 5	$ 5	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 46
24	Fuel Handling	$ 698	$ 673	$ 400	$ 306	$ 230	$ 481	$ 585	$ 528	$ 382	$ 478	$ 437	$ 637	$ 5,835
25	Affiliated Transportation	$ 1,202	$ 1,066	$ 776	$ 409	$ 572	$ 1,300	$ 1,946	$ 1,655	$ 1,200	$ 1,747	$ 1,704	$ 934	$ 14,510
26	Ash Disposal Cost/Credits	$ 190	$ 175	$ 175	$ 176	$ 176	$ 176	$ 176	$ 176	$ 176	$ 176	$ 176	$ 176	$ 2,121
27														
28	Total Power Supply Cost	$ 38,373	$ 31,781	$ 35,107	$ 33,877	$ 34,841	$ 40,282	$ 39,961	$ 37,877	$ 44,720	$ 47,754	$ 50,992	$ 34,083	$ 469,647
29														
30	Net Energy Requirement (GWh)	2,203.0	1,981.1	2,045.1	1,824.2	1,903.7	2,055.5	2,261.1	2,177.2	1,888.7	1,906.0	1,925.4	2,063.9	24,234.9
31														
32	PSCR Fuel Factor (mills/kWh) w/o Losses	17.41	16.04	17.16	18.57	18.30	19.59	17.67	17.39	23.67	25.05	26.48	16.51	19.37

INDIANA MICHIGAN POWER COMPANY
2017-2021 MICHIGAN PSCR PLAN
Net Energy Requirement
GWH

Line No.	Description	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	2017 Total
1	**Generation**													
2	Fossil	780.3	752.7	445.4	335.7	251.8	529.0	644.7	580.1	418.1	525.3	481.4	698.8	6,443.2
3	Nuclear	1,588.9	1,435.1	1,588.9	1,537.6	1,557.8	1,493.9	1,522.4	1,524.6	1,220.9	817.8	845.6	1,588.9	16,722.4
4	Hydro	10.2	9.5	11.6	12.1	10.3	9.0	8.2	7.4	7.1	7.3	8.6	10.8	112.1
5	Solar	1.0	1.3	2.1	2.4	2.9	3.0	3.0	2.7	2.3	1.8	1.0	0.8	24.4
6	Total Generation	2,380.5	2,198.7	2,048.0	1,887.8	1,822.8	2,034.9	2,178.3	2,114.8	1,648.4	1,352.1	1,336.6	2,299.3	23,302.1
7														
8	plus:													
9														
10	Purchased Power													
11	Market Purchases	3.5	3.7	38.3	9.0	31.8	36.8	45.4	62.4	171.5	275.9	329.4	16.3	1,024.1
12	AEG	546.2	526.9	311.8	235.0	176.3	370.3	451.3	406.1	292.7	367.7	337.0	489.2	4,510.2
13	OVEC	82.4	76.5	58.2	41.2	51.3	59.8	66.4	63.2	50.3	33.1	47.2	59.4	689.2
14	Other System Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Wind Purchases	152.8	131.2	141.0	142.0	112.7	81.6	59.5	47.8	59.1	123.9	150.3	146.2	1,348.1
16	Solar Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Total Purchased Power	784.9	738.3	549.1	427.2	372.2	548.5	622.6	579.6	573.6	800.6	863.9	711.1	7,571.5
18														
19	less:													
20														
21	Energy for System Sales	962.4	955.9	552.0	490.9	291.2	527.8	539.8	517.2	333.3	246.6	275.1	946.5	6,638.7
22														
23	Net Energy Requirement	2,203.0	1,981.1	2,045.1	1,824.2	1,903.7	2,055.5	2,261.1	2,177.2	1,888.7	1,906.0	1,925.4	2,063.9	24,234.9

Exhibit IM-16 (NAH-3)

INDIANA MICHIGAN POWER COMPANY
2017-2021 MICHIGAN PSCR PLAN
TOTAL COMPANY - MICHIGAN BASIS
($000)

Line No.	Description	2017 Total	2018 Total	2019 Total	2020 Total	2021 Total
1	**Fuel Costs**					
2	Fossil Generation	$ 159,556	$ 176,690	$ 181,753	$ 164,148	$ 170,559
3	Nuclear Generation	$ 133,268	$ 125,376	$ 108,544	$ 105,306	$ 101,524
4	Solar Generation	$ 1,770	$ 1,823	$ 1,871	$ 1,912	$ 1,925
5						
6	Total Fuel Cost	$ 294,593	$ 303,889	$ 292,168	$ 271,366	$ 274,008
7						
8	Plus:					
9	Allowance Consumption	$ 1,948	$ 1,949	$ 1,634	$ 1,275	$ 1,190
10	Consumables	$ 17,253	$ 17,377	$ 17,402	$ 17,577	$ 17,524
11	Purchased Power Non-Affil	$ 70,934	$ 55,045	$ 62,552	$ 62,914	$ 66,835
12	Purchased Power - Wind	$ 73,213	$ 74,484	$ 75,610	$ 98,624	$ 96,107
13	Purchased Power - Solar	$ -	$ -	$ -	$ 2,463	$ 6,148
14	Purchased Power - AEG	$ 255,438	$ 292,905	$ 292,201	$ 273,621	$ 281,451
15	PJM Ancillaries	$ 8,406	$ 8,406	$ 8,406	$ 8,406	$ 8,406
16	FTR Revenue Net of Congestion Costs - LSE	$ -	$ -	$ -	$ -	$ -
17	Transmission Losses	$ 11,600	$ 11,600	$ 11,600	$ 11,600	$ 11,600
18						
19						
20	Less:					
21	Off-System Sales Revenue COGS	$ 203,397	$ 250,168	$ 240,938	$ 268,517	$ 288,347
22	Off-System Sales Margin (80%)	$ 37,829	$ 46,079	$ 59,409	$ 65,325	$ 74,191
23	Allowance Gains/(Losses)	$ 46	$ 61	$ 14	$ 16	$ 18
24	Fuel Handling	$ 5,835	$ 6,458	$ 6,580	$ 5,695	$ 5,823
25	Affiliated Transportation	$ 14,510	$ 13,228	$ 15,335	$ 12,369	$ 8,508
26	Ash Disposal Cost/Credits	$ 2,121	$ 2,161	$ 2,168	$ 2,175	$ 2,181
27						
28	Total Power Supply Cost	$ 469,647	$ 447,499	$ 437,129	$ 393,750	$ 384,202
29						
30	Net Energy Requirement (GWh)	24,234.9	23,718.2	23,625.2	22,593.8	22,001.4
31						
32	PSCR Fuel Factor (mills/kWh) w/o Losses	19.37	18.86	18.50	17.42	17.46

Exhibit IM-17 (NAH-4)

INDIANA MICHIGAN POWER COMPANY
2017-2021 MICHIGAN PSCR PLAN
Net Energy Requirement
GWH

Line No.	Description	2017 Total	2018 Total	2019 Total	2020 Total	2021 Total
1	**Generation**					
2	Fossil	6,443.2	6,948.2	6,955.6	5,980.9	5,983.0
3	Nuclear	16,722.4	17,616.9	16,799.8	17,750.8	17,616.1
4	Hydro	112.1	110.1	111.7	111.4	111.4
5	Solar	24.4	24.3	24.2	24.1	23.9
6	Total Generation	23,302.1	24,699.5	23,891.3	23,867.2	23,734.5
7						
8	plus:					
9						
10	Purchased Power					
11	Market Purchases	1,024.1	366.5	532.1	388.8	357.1
12	AEG	4,510.2	4,863.7	4,868.9	4,186.6	4,188.1
13	OVEC	689.2	686.0	688.2	688.5	689.5
14	Other System Purchases	-	-	-	-	-
15	Wind Purchases	1,348.1	1,348.1	1,348.1	1,853.5	1,847.4
16	Solar Purchases	-	-	-	30.8	76.6
17	Total Purchased Power	7,571.5	7,264.3	7,437.3	7,148.2	7,158.7
18						
19	less:					
20						
21	Energy for System Sales	6,638.7	8,245.5	7,703.4	8,421.7	8,891.7
22						
23	Net Energy Requirement	24,234.9	23,718.2	23,625.2	22,593.8	22,001.4

DIRECT TESTIMONY OF CAROLE A. MYSER
ON BEHALF OF
INDIANA MICHIGAN POWER COMPANY
2017 PSCR PLAN CASE

Q. Would you please state your name and business address?

A. My name is Carole A. Myser. My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. By whom are you employed, and what is your position?

A. I am employed by American Electric Power (AEP) Service Corporation (AEPSC) as Manager–Transmission Settlements. AEPSC supplies engineering, financing, accounting, and similar planning and advisory services to the subsidiaries of the American Electric Power System including Indiana Michigan Power Company (I&M or Company).

Q. Would you please describe your educational and professional background?

A. I graduated from Wittenberg University in 1984 with a Bachelor of Arts degree in Business Administration with an Accounting emphasis. I was employed by the Firm now known as Deloitte & Touche as a Tax Consultant from 1984-87. In 1987, I joined AEPSC in the Tax Department and held various positions progressing to a Senior Tax Analyst. In 1998 I was promoted to a Transmission Marketing Analyst in Transmission Operations. Since 2003 I have progressed through several management levels in various departments: Manager-Transmission Marketing in Transmission Strategy & Business Development (2003), Manager Investor Relations (2005), Manager-Financial

Reporting (2006), Manager – Transmission Settlements in Transmission Operations (2008), and Manager – Transmission Settlements in Transmission Settlements & Investments (2012). I am a Certified Public Accountant in Ohio.

Q. What are your responsibilities as Manager – Transmission Settlements?

A. I am primarily responsible for the forecasting of transmission revenue and expenses, RTO transmission settlements reconciliations, and other third party transmission settlement activities.

Q. Have you previously submitted testimony in any regulatory proceedings?

A. Yes. I submitted testimony before the Michigan Public Service Commission (MPSC) in I&M's Power Supply Cost Recovery Plan cases for the plan years of 2012 through 2016 and I&M's 2012 through 2015 Power Supply Cost Recovery Reconciliation cases.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present the forecasts of the Company's monthly Open Access Transmission Tariff (OATT) expenses for the period January 2017 through December 2017 and annual OATT expenses for the years 2017 through 2021. I will also describe the methodologies employed to derive I&M's estimated OATT expenses.

Q. What exhibits are you sponsoring in this proceeding?

A. I am sponsoring the following exhibit:

- Exhibit IM-18 (CAM-1) identifies, by component, the forecasted monthly OATT expenses for the period January 2017 through December 2017, as well as the annual forecasted OATT expenses for 2017 - 2021.

Q. Would you please describe the OATT charges and credits included in the 2017 PSCR plan and proposed PSCR factors?

A. Based on the Commission's Order in Case No. U-16801, the charges and credits which constitute I&M's OATT expenses to be reflected in the PSCR factor are:

1. Network Integration Transmission Service (NITS);
2. Firm and Non-Firm Point-to-Point (PTP) Transmission Credits;
3. Schedule 1A Ancillary Service Charges;
4. PJM Transmission Enhancement Charges;
5. PJM Administration Fees;
6. RTO Start-up Cost Recovery Charges (SCRC)

Q. Please provide a general description of the OATT charges and credits and the methodologies utilized in the development of I&M's forecasted OATT expenses for the period of 2017 – 2021.

A. A discussion of the specific methodologies and assumptions used in the derivation of each of these items by category follows.

<u>**Network Integrated Transmission Service**</u>

Q. What are Network Integrated Transmission Service charges?

A. These are wholesale transmission expenses allocated to I&M for the company's usage of the AEP transmission system in PJM. PJM allocates a portion of the total costs required to provide reliable network transmission service to each load serving entity (LSE) in the AEP transmission zone. As an LSE, AEP is allocated a portion of the NITS costs, which it further allocates to its operating companies.

The AEP East Companies' charges are computed by applying the zonal NITS rate to the total AEP LSE Network Service Peak Load (NSPL) of the prior calendar year, coincident with the prior calendar year NSPL of the entire AEP zone. The NITS rates are calculated using the formula rates specified in Attachments H-14 and H-20 of the PJM OATT. The NITS rates are updated annually effective July 1. Pursuant to Appendix 1 of the Transmission Agreement, approved by the FERC on October 29, 2010 (FERC Docket No. ER09-1279-000), the NITS charges incurred by the AEP East Companies to serve load in the AEP Zone of PJM are further allocated to I&M based on its contribution to the AEP LSE average 12 month coincident peak (12CP) transmission load through October 31 of the prior year.

Q. How was the projection of Network Integrated Transmission Service expense developed?

A. I&M's projected NITS expense was developed using two methods. First, because the NITS rate has already been approved by the FERC (Docket Nos. ER08-1329-000 and ER10-355-000) for the period of January – June 2017, this rate is used to forecast total monthly NITS charges for this time period. The total AEP East NITS charge is determined by multiplying the NITS rate by the prior calendar year NSPL of the AEP East LSEs in PJM. Once the total AEP NITS charge is forecasted, I&M's share of the charge is calculated based on its pro rata share of the AEP East Operating Companies' 12CP load.

To forecast the NITS expenses beyond the effective period of the FERC approved billing determinants, transmission revenue requirement projections are forecasted. Load forecasts received from AEP's Economic Forecasting group are used to estimate future peak loads. These forecasted transmission revenue requirements are applied to project monthly NITS charges for the AEP East Operating Companies in PJM. The projected NITS charges are then allocated to I&M based on its projected 12CP load share.

Firm and Non-Firm Point-to-Point Transmission Credits

Q. What are Firm and Non-Firm Point-to-Point transmission credits?

A. Each month, PJM allocates Firm PTP transmission service revenues to the various PJM Transmission Zones, proportionate to the revenue requirements for NITS in each zone. Non-Firm PTP is allocated proportionately to the monthly demand charges. PJM further allocates the AEP Zone share of PJM PTP revenues directly to AEP and other NITS customers in the AEP Zone. I&M is then allocated a portion of AEP's PTP credits based on its 12CP load share.

Q. How did you forecast Firm and Non-Firm PTP transmission credits?

A. PTP transmission credits are forecasted using the latest available actual credits appearing on the PJM Settlement statement based on recent transmission service reservations. For 2017, an average of I&M's actual monthly PTP transmission credit for the 12 month period ending June 2016 was used to derive a monthly total applied to January – December 2017. This number was held constant as a reasonable forecast because in outer years demand for PTP transmission reservations is less reasonably predictable over the long term.

<u>Schedule 1A Ancillary Service Charges</u>

Q. What are Schedule 1A ancillary service charges?

A. These are charges paid by AEP to PJM for transmission scheduling and dispatch services provided by AEP East Operating Companies. PJM OATT Schedule 1A includes a rate, specified in $/MWh, for Scheduling, System Control and Dispatch Service provided by PJM Transmission Owners in each PJM Zone. The rate for that service is updated annually with the NITS formula rate updates discussed above.

Q. How was the projection of Schedule 1A ancillary service charges developed?

A. For the period of January – June 2017, the rate used in billing for Schedule 1A charges has been approved by the FERC (Docket No. ER08-1329-000). This rate is held constant throughout the forecast period. To forecast I&M's Schedule 1A charge in 2017, the current FERC approved Schedule 1A rate is multiplied by the total AEP LSE energy (MWh) forecasted for calendar year 2017 to derive the total AEP Schedule 1A charge. I&M's share of the total

AEP Schedule 1A charge is calculated by applying the current FERC approved Schedule 1A rate to I&M's share of the forecasted load.

PJM Transmission Enhancement Charges

Q. What are PJM Transmission Enhancement charges?

A. The Transmission Enhancement expenses are paid by AEP to PJM to help fund investment in extra-high voltage transmission projects that are determined to be needed to maintain reliability throughout the entire PJM footprint (regional projects). The costs resulting from Regional Projects are allocated to the PJM Zones that are deemed to benefit from each project. The cost responsibility allocated to each zone for all Regional Transmission Expansion Plan (RTEP) projects is charged to NITS customers based on their respective NSPL shares. AEP then allocates a portion of its assigned transmission enhancement costs to I&M based on its 12CP load share.

Q. How was the projection of PJM Transmission Enhancement charges developed?

A. The latest transmission project information published by PJM is used to estimate transmission revenue requirements for regional projects with costs approved to be allocated to the AEP Zone. The latest FERC approved PJM regional cost allocation policy is used to estimate the portion of each project that can be expected to be allocated to the AEP Zone for the period 2017 - 2021. Of the total forecasted AEP Transmission Enhancement charge, I&M is allocated a percentage based on its forecasted share of the average 12CP.

The forecast presented through my testimony assumes that FERC will approve, without modification, an offer of settlement executed and/or supported by numerous PJM transmission owners, the affected state utility commissions, and FERC trial staff related to the assignment of cost responsibility for RTEP projects at or above 500 kV that the PJM Board approved prior to February 1, 2013. The relevant offer of settlement was submitted in FERC Docket No. EL05-121-009. Although a small number of parties to the proceeding contested the offer of settlement, the forecast assumes that FERC will approve it based on its broad support among transmission owners and state utility commissions across the PJM footprint, whose litigation positions were diverse.

PJM Administrative Charges

Q. What are PJM Administrative charges?

A. PJM charges each market participant on a monthly basis a number of fees to recover its operating and administration costs. PJM also charges fees to transmission customers and other market participants to fund the operation of the Federal Energy Regulatory Commission (FERC) and certain other organizations that are involved in management of transmission reliability and regulation. These fees are defined in PJM OATT Schedules 9 and 10, and are approved by the FERC. Administrative costs incurred by the PJM RTO are passed on to member LSEs and generation owners through an energy based rate ($/MWh). PJM directly assigns the Administrative charges to the operating companies based on usage.

Q. How was the projection of PJM Administrative charges developed?

A. We used the available projected administrative fee rate information for 2015 - 2018 released by PJM to project charges for the entire forecast period. Historical actual charges were adjusted proportionally to the projected rates for 2015 - 2018. An annual estimated growth rate of 2% is applied for the period 2019 – 2021. I&M's projected share of the total PJM administrative charge is determined by I&M's historical expense allocation.

<u>RTO Start-Up Cost Recovery Charges</u>

Q. What are RTO Start-Up Cost Recovery Charges?

A. The RTO Start-Up Cost Recovery Charges recover the AEP East Companies' direct costs for RTO development and start-up. The charge is only billed to customers in the AEP Zone in PJM. The SCRC rate collects the costs associated with the AEP East Operating Companies joining PJM and FERC-approved carrying costs over a fifteen-year amortization period scheduled to end in 2020.

Q. How was the projection of RTO Start-up Cost Recovery Charges developed?

A. Collectively, the AEP Zone in PJM is annually charged $2,362,185, plus any applicable true-up adjustment, for RTO SCRC. Because the RTO SCRC charge is an amortized expense, we do not forecast a significant change in

I&M's expenses for this charge. Therefore, we used a historical 12 month average to project these expenses for the forecast period.

Q. How were these projected OATT costs included in I&M's projected PSCR costs?

A. The projected OATT costs are incorporated in the development of the proposed PSCR factor as described by witness Hille.

Q. Does this conclude your pre-filed direct testimony?

A. Yes.

Indiana Michigan Power Company
Total Company Projected OATT Expenses

Basis for Cost Allocation ($000)

Line No.	Description	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Total 2017
	Total I&M													
1	PJM Administrative Charges	719	693	726	686	575	827	786	793	717	576	661	700	8,459
	Retail Energy Only													
2	Schedule 1A Ancillary Service Charges	165	145	151	132	140	151	171	165	138	143	146	153	1,800
	Retail Demand Only													
3	Network Integration Transmission Service (NITS) Charges	12,428	11,225	12,428	12,027	12,428	12,027	15,937	15,937	15,423	15,937	15,423	15,937	167,157
4	Firm and Non-Firm Point to Point Transmission Credits	(150)	(128)	(119)	(105)	(110)	(105)	(144)	(128)	(118)	(123)	(100)	(130)	(1,460)
5	PJM Transmission Enhancement Charges	1,708	1,708	1,708	1,708	1,708	1,753	1,614	1,614	1,614	1,614	1,614	1,614	19,977
6	RTO Start-up Cost Recovery Charges	34	34	34	34	34	34	34	34	34	34	34	34	408

Indiana Michigan Power Company
Total Company Projected OATT Expenses

Basis for Cost Allocation ($000)

Line No.	Description	Annual 2017	Annual 2018	Annual 2019	Annual 2020	Annual 2021
	Total I&M					
1	PJM Administrative Charges	8,459	8,484	8,471	8,598	8,727
	Retail Energy Only					
2	Schedule 1A Ancillary Service Charges	1,800	1,759	1,751	1,670	1,624
	Retail Demand Only					
3	Network Integration Transmission Service (NITS) Charges	167,157	212,506	243,699	266,822	296,369
4	Firm and Non-Firm Point to Point Transmission Credits	(1,460)	(1,459)	(1,459)	(1,459)	(1,459)
5	PJM Transmission Enhancement Charges	19,977	20,271	21,075	20,737	22,821
6	RTO Start-up Cost Recovery Charges	408	408	408	170	0

DIRECT TESTIMONY OF DAVID L. HILLE
ON BEHALF OF
INDIANA MICHIGAN POWER COMPANY
2017 PSCR PLAN CASE

Q. Please state your name and business address.

A. My name is David L. Hille. My business address is Indiana Michigan Power Center, P. O. Box 60, Fort Wayne, Indiana 46801.

Q. By whom are you employed and in what capacity?

A. I am employed by Indiana Michigan Power Company (I&M or Company) as Regulatory Consultant Staff in the Regulatory Services Department.

Q. Please briefly describe your educational and business experience.

A. I graduated from Ball State University in 1983 with a Bachelor of Science Degree in Accounting. After graduating in 1983, I joined American Electric Power Service Corporation as an Auditor Assistant performing operational reviews of the area offices of I&M and Michigan Power Company. As an internal auditor, I became experienced in the process of inspecting and analyzing data and then drawing conclusions and reporting findings based on the data inspected.

In May 1986, I accepted a position in I&M's Rates and Tariffs Department as a Rate Analyst. My duties included preparing data used in formal and informal rate proceedings that included monthly, quarterly, and annual filings.

In September 1991, I was named to Senior Rate Analyst. My duties in that position involved the accumulation, documentation, presentation, and review of data for various rate proceedings. In January 1996, I became

Manager of Rates and Regulations responsible for matters concerning various rate proceedings and fuel factors and the supervision of the preparation of various reports or studies, as required. In particular, I am responsible for preparing or reviewing I&M's monthly Power Supply Cost Recovery (PSCR) reports and coordinating the preparation and filing of I&M's annual PSCR plan and reconciliation cases. The department and my position were later changed to Regulatory Services and Senior Regulatory Consultant, respectively, and I have since been named Regulatory Consultant Staff but my central responsibilities remained the same. I directly report to the Director of Regulatory Services

Q. Have you previously submitted testimony in any regulatory proceedings?

A. Yes. I testified before the Michigan Public Service Commission (MPSC) in I&M's 1996, 1997, and 2004 PSCR Plan Cases and I&M's 1996 and 1997 PSCR Reconciliation Cases. I also submitted testimony to the MPSC in I&M's 1995, 1998, 1999, 2000, and 2005 through 2016 PSCR Plan Cases and I&M's 1994, 1995, 1998, and 2004 through 2015 PSCR Reconciliation Cases. In addition, I have testified before the Indiana Utility Regulatory Commission in I&M's fuel cost proceedings.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to support the calculation of I&M's PSCR Plan Case factors for each of the billing months of January through December 2017, describe the estimated roll-in over/under-recoveries from the 2016 PSCR Plan case, and support the resultant revised tariff sheet.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, Exhibit IM-19 (DLH-1), page 1 of 2, shows the calculation of the proposed PSCR factor applicable to the billing months of January through December 2017. Page 2 of 2 shows the estimated under-recovery expected at the end of the 2016 PSCR plan year. Exhibit IM-20 (DLH-2) calculates the applicable transmission factor includable within the PSCR clause. Exhibit IM-21 (DLH-3) contains the revised tariff sheet that reflects the proposed PSCR factor.

Q. How did you calculate the proposed PSCR factor?

A. The PSCR factor was calculated in accordance with the methodology approved in I&M's most recent general base rate proceeding, Case No. U-16801. As shown on Exhibit IM-19 (DLH-1), page 1 of 2, I calculated the proposed PSCR factor using data provided by Witness Heimberger by dividing the sum of the monthly forecasted costs by the sum of the monthly net energy requirements, adjusting the resulting quotient for losses by applying a 4.6% loss factor, adding the PSCR transmission factor, and then subtracting the 23.77 mills per kWh power supply cost base approved in Case No. U-16801. In addition, the effect of the roll-in methodology, shown on line 8, results in a proposed PSCR factor of 10.50 mills per kWh applicable to the billing months of January through December 2017.

Q. Why did you use a 4.6% loss factor?

A. In accordance with the Order Approving Settlement Agreement in MPSC Case No. U-16801, the 4.6% loss factor established in that proceeding shall be used for PSCR purposes until a new loss factor is established in a subsequent base rate case.

Q. Does the proposed PSCR factor include costs related to transmission?

A. Yes. Consistent with the Order Approving Settlement Agreement in MPSC Case No. U-16801, I&M’s most recent base rate case, the PSCR factor includes those transmission items established in that case.

Q. How were amounts related to those transmission items forecasted?

A. A description of the transmission items and the forecasted amounts are supported by Witness Myser.

Q. How was the factor associated with these transmission items determined?

A. As set forth in the methodology in Case No. U-16801, the projected amounts, by category, are divided by the projected net energy requirement as supplied by Witness Heimberger, then multiplied by the respective allocation adjustment and loss factor at levels established in the base rate case. The transmission factors are shown on Exhibit IM-20 (DLH-2).

Q. What is the result of these calculations?

A. As shown on Exhibit IM-20 (DLH-2) the 2017 projected transmission factor is 10.70 mills/kWh.

Q. Where is the proposed PSCR factor reflected in I&M's tariffs?

A. I&M's proposed PSCR factor is included on Sheet No. D-110.00, as shown in Exhibit IM-21 (DLH-3). When the Commission issues an order approving the 2017 PSCR Plan factor, the approved factor will be reflected on Sheet No. D-110.00.

Q. Can you briefly describe the benefits of the roll-in methodology?

A. The roll-in method spreads the over/under-recovery amount across all twelve months of the plan year, minimizing its impact on customers while providing rate stability. In addition, the roll-in methodology is administratively more efficient and cost effective for I&M than the prior refund/surcharge method. Furthermore, when a refund or surcharge appears on customer's bills during specified months this increases customer inquires and volatility in customer bills. In summary, I&M believes the roll-in methodology provides customers with better rate stability, improves bill clarity, minimizes customer confusion and uncertainty, and is more administratively and cost efficient.

Q. Are you aware if the roll-in methodology has been implemented by other companies?

A. It is my understanding that this methodology is being utilized in numerous PSCR and Gas Cost Recovery (GCR) filings of various companies.

Q. Please describe Exhibit IM-19 (DLH-1), page 2 of 2.

A. Exhibit IM-19 (DLH-1), page 2 of 2, sets forth by month, I&M's current 2016 plan year actual and estimated over/under-recoveries. Actual over/under recovered amounts are shown for January through July 2016 and, preliminary over/under-recoveries are shown for August along with estimates for the balance of the year. The calculation of interest, for both actual and estimated over/under-recovery balances, has been performed in the same manner as past I&M reconciliation cases. The estimated annual under-recovery amount, including interest, is $9,242,535. Consistent with the roll-in methodology approved by the MPSC in Case No. U-15004, this under-recovered amount has been rolled into the 2017 Plan Year's proposed power supply cost recovery factor calculation as shown on Exhibit IM-19 (DLH-1), page 1 of 2.

Q. How are over or under-recoveries determined in the annual PSCR reconciliation?

A. There are no changes in the way over or under-recoveries are determined in the annual PSCR reconciliation.

Q. Does I&M plan to accrue interest on over/under-recoveries?

A. Yes, over and under-recoveries will accrue interest on a monthly basis during the 12 month PSCR period at the rates prescribed in Act 304.

Q. What is the net effect on customers' bills as a result of the proposed PSCR Plan Case factors?

A. I&M's customers will experience an increase of 1.61 mills per kWh as a result of the proposed factor of 10.50 mills per kWh.

Q. Are I&M's policies and the costs included in this plan reasonable and prudent and in accordance with the provisions of Act 304?

A. Yes. I&M's objective is to achieve the lowest total unit cost of electricity to customers over the long term while insuring an adequate and reliable supply of energy. The testimony of Witness West addresses I&M's sources and cost of coal and the testimony of Witness Bellville illustrates how I&M's fuel procurement practices minimize the cost of nuclear fuel, while the testimony of Witnesses Baker and Heimberger support the overall sources of power supply of I&M’s expected demand and net energy requirements to meet its objective. Furthermore, Witness Myser supports the manner in which AEP’s OATT meets this objective.

Q. Does this complete your direct testimony?

A. Yes.

Indiana Michigan Power Company
Determination of the Michigan Jurisdiction
Power Supply Cost Recovery Factor
January 2017 - December 2017

Line No.	Description	Twelve Month Totals	
1	Total Power Supply Costs (000's)	$469,647	
2	Net Energy Requirement (GWh)	24,235	
3	Line 1 / Line 2	19.37	Mills/kWh
4	Line 3 * 1.046	20.26	Mills/kWh
5	Plus: PSCR Transmission Factor (See Exhibit DLH-2)	10.70	Mills/kWh
6	Less Current Power Supply Cost Base	23.77	Mills/kWh
7	Subtotal - Line 4 plus Line 5 less Line 6	7.19	Mills/kWh
8	Estimated 2016 Under-recovery of $9,242,535/ 2,789,000,000 Est'd kWh 2017	3.31	Mills/kWh
9	PSCR Billing Factor for the Michigan Jurisdiction - Line 7 + Line 8	10.50	Mills/kWh

Indiana Michigan Power Company
Current 2017 PSCR Plan Year Over/(Under) Recoveries
Michigan Jurisdiction

	Description	Actual Jan	Actual Feb	Actual Mar	Actual Apr	Actual May	Actual Jun	Actual Jul	Preliminary Aug	Estimated Sep	Estimated Oct	Estimated Nov	Estimated Dec	Total
1	Sales subject to PSCR (KWh)	258,600,062	244,197,133	230,163,674	215,428,641	201,163,122	229,951,848	255,168,850	278,402,821	245,600,000	213,700,000	212,600,000	242,300,000	2,827,276,151
2	PSCR Base Incl Losses (Mills/kWh)	23.77	23.77	23.77	23.77	23.77	23.77	23.77	23.77	23.77	23.77	23.77	23.77	
3	PSCR Factor (Mills/kWh)	8.89	8.89	8.89	8.89	8.89	8.89	8.89	8.89	8.89	8.89	8.89	8.89	
4	Total PSCR Revenues Lines [1*(2 + 3)]	8,445,878	7,975,479	7,517,146	7,035,899	6,569,988	7,510,227	8,333,815	9,092,636	8,021,296	6,979,442	6,943,516	7,913,518	$92,338,840
5	Applicable Power Costs	7,866,614	7,430,919	7,123,566	8,313,391	6,248,127	6,969,841	8,905,393	9,008,005	7,984,456	7,951,777	8,185,100	8,291,506	$94,278,695
6	Over/(Under) Recovery Lines [4 - 5]	$579,264	$544,560	$393,580	($1,277,492)	$321,861	$540,386	($571,578)	$84,631	$36,840	($972,335)	($1,241,584)	($377,988)	($1,939,855)
7	Beginning Recovery Balance (1)	($7,230,400)	($6,651,136)	($6,106,576)	($5,712,996)	($6,990,488)	($6,668,627)	($6,143,876)	($6,715,454)	($6,630,823)	($6,593,983)	($7,566,318)	($8,807,902)	
8	Ending Recovery Balance Lines [6 + 7]	($6,651,136)	($6,106,576)	($5,712,996)	($6,990,488)	($6,668,627)	($6,128,241)	($6,715,454)	($6,630,823)	($6,593,983)	($7,566,318)	($8,807,902)	($9,185,890)	
	Adjusted Ending Recovery Balance (2)						($6,143,876)							
9	Average Recovery Balance Lines [7 + 8] / 2	($6,940,768)	($6,378,856)	($5,909,786)	($6,351,742)	($6,829,558)	($6,398,434)	($6,429,665)	($6,673,139)	($6,612,403)	($7,080,151)	($8,187,110)	($8,996,896)	
10	Applicable Interest Rate	0.72%	0.72%	0.75%	0.76%	0.75%	0.79%	0.86%	0.89%	0.89%	0.89%	0.89%	0.89%	
11	Monthly Interest Lines [9 * 10] / 12	($4,164)	($3,827)	($3,694)	($4,023)	($4,268)	($4,212)	($4,608)	($4,949)	($4,904)	($5,251)	($6,072)	($6,673)	($56,645)
12	YTD Interest	($4,164)	($7,991)	($11,685)	($15,708)	($19,976)	($24,188)	($28,796)	($33,745)	($38,649)	($43,900)	($49,972)	($56,645)	
13	Rolling Over/(Under) Recovery Lines [8 + 12]	($6,655,300)	($6,114,567)	($5,724,681)	($7,006,196)	($6,688,603)	($6,152,429)	($6,744,250)	($6,664,568)	($6,632,632)	($7,610,218)	($8,857,874)	($9,242,535)	
									Total Underrecovery and Interest					($9,242,535)

(1) January beginning balance represents the amount as approved in the 2015 PSCR Reconciliation Case U-17679-R.

(2) June's Adjusted Ending Recovery Balance reflects an adjustment of $15,635 in accordance with the Order Approving Settlement Agreement in Case No. U-17037 Enhanced Nuclear Security Costs.

Indiana Michigan Power Company
Total Company Projected OATT Expenses

Line No.	Basis for Cost Allocation ($000) Description	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17
1	**Total I&M**						
2	PJM Administrative Charges	719	693	726	686	575	827
3	PJM Administrative Charge - Default assessments	0	0	0	0	0	0
4	**Subtotal I&M**	**719**	**693**	**726**	**686**	**575**	**827**
5	Net Energy Requirement (GWh)	2,203	1,981	2,045	1,824	1,904	2,056
6	Transmission Cost (mills/kWh) w/o Losses (L4/L5)	0.33	0.35	0.36	0.38	0.30	0.40
7	Allocation Adjustment (L46)	1.0023	1.0023	1.0023	1.0023	1.0023	1.0023
8	Transmission Factor (mills/kWh) w/o Losses (L6xL7)	0.33	0.35	0.36	0.38	0.30	0.40
9	Loss Correction Multiplier	1.046	1.046	1.046	1.046	1.046	1.046
10	**TOTAL I&M Transmission Factor (mills/kWh) w/ Losses (L8xL9)**	**0.34**	**0.37**	**0.37**	**0.39**	**0.32**	**0.42**
11							
12	**Retail Energy Only**						
13	Schedule 1A Ancillary Service Charges	165	145	151	132	140	151
14	(Transmission Owner Scheduling, System Control and Load Dispatching)						
15	**Subtotal Retail Energy Only**	**165**	**145**	**151**	**132**	**140**	**151**
16	Net Energy Requirement (GWh)	2,203	1,981	2,045	1,824	1,904	2,056
17	Transmission Cost (mills/kWh) w/o Losses (L15/L16)	0.07	0.07	0.07	0.07	0.07	0.07
18	Allocation Adjustment (L46)	1.2932	1.2932	1.2932	1.2932	1.2932	1.2932
19	Transmission Factor (mills/kWh) w/o Losses (L17xL18)	0.10	0.09	0.10	0.09	0.10	0.09
20	Loss Correction Multiplier	1.046	1.046	1.046	1.046	1.046	1.046
21	**Retail Energy Transmission Factor (mills/kWh) w/ Losses (L19xL20)**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**
22							
23	**Retail Demand Only**						
24	Network Integration Transmission Service (NITS) Charges	12,428	11,225	12,428	12,027	12,428	12,027
25	Firm and Non-Firm Point to Point Transmission Credits	(150)	(128)	(119)	(105)	(110)	(105)
26	PJM Transmission Enhancement Charges	1,708	1,708	1,708	1,708	1,708	1,753
27	RTO Start-up Cost Recovery Charges	34	34	34	34	34	34
28	PJM Expansion Cost Recovery Charges	0	0	0	0	0	0
29	Revised Transmission Agreement Phase-In Credits	0	0	0	0	0	0
30	**Subtotal Retail Demand Only**	**14,020**	**12,839**	**14,051**	**13,664**	**14,060**	**13,709**
31	Net Energy Requirement (GWh)	2,203	1,981	2,045	1,824	1,904	2,056
32	Transmission Cost (mills/kWh) w/o Losses (L30/L31)	6.36	6.48	6.87	7.49	7.38	6.67
33	Allocation Adjustment (L46)	1.274	1.274	1.274	1.274	1.274	1.274
34	Transmission Factor (mills/kWh) w/o Losses (L32xL33)	8.11	8.26	8.75	9.54	9.41	8.50
35	Loss Correction Multiplier	1.046	1.046	1.046	1.046	1.046	1.046
36	**Retail Demand Transmission Factor (mills/kWh) w/ Losses (L34xL35)**	**8.48**	**8.64**	**9.16**	**9.98**	**9.84**	**8.89**
37							
38	**Transmission Factor (mills/kWh) w/ Losses (L10+L21+L36))**	**8.92**	**9.10**	**9.63**	**10.48**	**10.26**	**9.41**
39							

Line No.		Total I&M	Retail Energy	Retail Demand
40	*Derivation of Allocation Adjustment*			
41				
42	Applicable Allocation Factor	14.28826%	18.43603%	18.16327%
43				
44	MI Energy Allocation Factor	14.25592%	14.25592%	14.25592%
45				
46	Allocation Adjustment (L42/L44)	1.0022685	1.2932192	1.27408613

Indiana Michigan Power Company
Total Company Projected OATT Expenses

Line No.	Basis for Cost Allocation ($000) Description	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Total 2017
1	**Total I&M**							
2	PJM Administrative Charges	786	793	717	576	661	700	8,459
3	PJM Administrative Charge - Default assessments	0	0	0	0	0	0	0
4	**Subtotal I&M**	**786**	**793**	**717**	**576**	**661**	**700**	**8,459**
5	Net Energy Requirement (GWh)	2,261	2,177	1,889	1,906	1,925	2,064	24,235
6	Transmission Cost (mills/kWh) w/o Losses (L4/L5)	0.35	0.36	0.38	0.30	0.34	0.34	0.35
7	Allocation Adjustment (L46)	1.0023	1.0023	1.0023	1.0023	1.0023	1.0023	1.0023
8	Transmission Factor (mills/kWh) w/o Losses (L6xL7)	0.35	0.37	0.38	0.30	0.34	0.34	0.35
9	Loss Correction Multiplier	1.046	1.046	1.046	1.046	1.046	1.046	1.046
10	**TOTAL I&M Transmission Factor (mills/kWh) w/ Losses (L8xL9)**	**0.36**	**0.38**	**0.40**	**0.32**	**0.36**	**0.36**	**0.37**
11								
12	**Retail Energy Only**							
13	Schedule 1A Ancillary Service Charges	171	165	138	143	146	153	1,800
14	(Transmission Owner Scheduling, System Control and Load Dispatching)							
15	**Subtotal Retail Energy Only**	**171**	**165**	**138**	**143**	**146**	**153**	**1,800**
16	Net Energy Requirement (GWh)	2,261	2,177	1,889	1,906	1,925	2,064	24,235
17	Transmission Cost (mills/kWh) w/o Losses (L15/L16)	0.08	0.08	0.07	0.08	0.08	0.07	0.07
18	Allocation Adjustment (L46)	1.2932	1.2932	1.2932	1.2932	1.2932	1.2932	1.2932
19	Transmission Factor (mills/kWh) w/o Losses (L17xL18)	0.10	0.10	0.09	0.10	0.10	0.10	0.10
20	Loss Correction Multiplier	1.046	1.046	1.046	1.046	1.046	1.046	1.046
21	**Retail Energy Transmission Factor (mills/kWh) w/ Losses (L19xL20)**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**
22								
23	**Retail Demand Only**							
24	Network Integration Transmission Service (NITS) Charges	15,937	15,937	15,423	15,937	15,423	15,937	167,157
25	Firm and Non-Firm Point to Point Transmission Credits	(144)	(128)	(118)	(123)	(100)	(130)	(1,460)
26	PJM Transmission Enhancement Charges	1,614	1,614	1,614	1,614	1,614	1,614	19,977
27	RTO Start-up Cost Recovery Charges	34	34	34	34	34	34	408
28	PJM Expansion Cost Recovery Charges	0	0	0	0	0	0	0
29	Revised Transmission Agreement Phase-In Credits	0	0	0	0	0	0	0
30	**Subtotal Retail Demand Only**	**17,441**	**17,457**	**16,953**	**17,462**	**16,971**	**17,455**	**186,082**
31	Net Energy Requirement (GWh)	2,261	2,177	1,889	1,906	1,925	2,064	24,235
32	Transmission Cost (mills/kWh) w/o Losses (L30/L31)	7.71	8.02	8.97	9.16	8.82	8.46	7.68
33	Allocation Adjustment (L46)	1.274	1.274	1.274	1.274	1.274	1.274	1.274
34	Transmission Factor (mills/kWh) w/o Losses (L32xL33)	9.83	10.22	11.43	11.67	11.23	10.77	9.78
35	Loss Correction Multiplier	1.046	1.046	1.046	1.046	1.046	1.046	1.046
36	**Retail Demand Transmission Factor (mills/kWh) w/ Losses (L34xL35)**	**10.28**	**10.69**	**11.96**	**12.21**	**11.75**	**11.27**	**10.23**
37								
38	**Transmission Factor (mills/kWh) w/ Losses (L10+L21+L36))**	**10.75**	**11.17**	**12.46**	**12.63**	**12.21**	**11.73**	**10.70**
39								

Line No.		Total I&M	Retail Energy	Retail Demand
40	*Derivation of Allocation Adjustment*			
41				
42	Applicable Allocation Factor	14.28826%	18.43603%	18.16327%
43				
44	MI Energy Allocation Factor	14.25592%	14.25592%	14.25592%
45				
46	Allocation Adjustment (L42/L44)	1.0022685	1.2932192	1.2740861

Indiana Michigan Power Company
Total Company Projected OATT Expenses

Line No.	**Basis for Cost Allocation ($000)** **Description**	Annual 2017	Annual 2018	Annual 2019	Annual 2020	Annual 2021
1	**Total I&M**					
2	PJM Administrative Charges	8,459	8,484	8,471	8,598	8,727
3	PJM Administrative Charge - Default assessments	0	0	0	0	0
4	**Subtotal I&M**	**8,459**	**8,484**	**8,471**	**8,598**	**8,727**
5	Net Energy Requirement (GWh)	24,235	23,718	23,625	22,594	22,001
6	Transmission Cost (mills/kWh) w/o Losses (L4/L5)	0.35	0.36	0.36	0.38	0.40
7	Allocation Adjustment (L46)	1.0023	1.0023	1.0023	1.0023	1.0023
8	Transmission Factor (mills/kWh) w/o Losses (L6xL7)	0.35	0.36	0.36	0.38	0.40
9	Loss Correction Multiplier	1.046	1.046	1.046	1.046	1.046
10	**TOTAL I&M Transmission Factor (mills/kWh) w/ Losses (L8xL9)**	**0.37**	**0.38**	**0.38**	**0.40**	**0.42**
11						
12	**Retail Energy Only**					
13	Schedule 1A Ancillary Service Charges	1,800	1,759	1,751	1,670	1,624
14	(Transmission Owner Scheduling, System Control and Load Dispatching)					
15	**Subtotal Retail Energy Only**	**1,800**	**1,759**	**1,751**	**1,670**	**1,624**
16	Net Energy Requirement (GWh)	24,235	23,718	23,625	22,594	22,001
17	Transmission Cost (mills/kWh) w/o Losses (L15/L16)	0.07	0.07	0.07	0.07	0.07
18	Allocation Adjustment (L46)	1.2932	1.2932	1.2932	1.2932	1.2932
19	Transmission Factor (mills/kWh) w/o Losses (L17xL18)	0.10	0.10	0.10	0.10	0.10
20	Loss Correction Multiplier	1.046	1.046	1.046	1.046	1.046
21	**Retail Energy Transmission Factor (mills/kWh) w/ Losses (L19xL20)**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**
22						
23	**Retail Demand Only**					
24	Network Integration Transmission Service (NITS) Charges	167,157	212,506	243,699	266,822	296,369
25	Firm and Non-Firm Point to Point Transmission Credits	(1,460)	(1,459)	(1,459)	(1,459)	(1,459)
26	PJM Transmission Enhancement Charges	19,977	20,271	21,075	20,737	22,821
27	RTO Start-up Cost Recovery Charges	408	408	408	170	0
28	PJM Expansion Cost Recovery Charges	0	0	0	0	0
29	Revised Transmission Agreement Phase-In Credits	0	0	0	0	0
30	**Subtotal Retail Demand Only**	**186,082**	**231,726**	**263,723**	**286,270**	**317,731**
31	Net Energy Requirement (GWh)	24,235	23,718	23,625	22,594	22,001
32	Transmission Cost (mills/kWh) w/o Losses (L30/L31)	7.68	9.77	11.16	12.67	14.44
33	Allocation Adjustment (L46)	1.274	1.274	1.274	1.274	1.274
34	Transmission Factor (mills/kWh) w/o Losses (L32xL33)	9.78	12.45	14.22	16.14	18.40
35	Loss Correction Multiplier	1.046	1.046	1.046	1.046	1.046
36	**Retail Demand Transmission Factor (mills/kWh) w/ Losses (L34xL35)**	**10.23**	**13.02**	**14.88**	**16.89**	**19.25**
37						
38	**Transmission Factor (mills/kWh) w/ Losses (L10+L21+L36))**	**10.70**	**13.50**	**15.35**	**17.38**	**19.76**
39						
40	*Derivation of Allocation Adjustment*	*Total I&M*		*Retail Energy*		*Retail Demand*
41						
42	Applicable Allocation Factor	14.28826%		18.43603%		18.16327%
43						
44	MI Energy Allocation Factor	14.25592%		14.25592%		14.25592%
45						
46	Allocation Adjustment (L42/L44)	1.0022685		1.2932192		1.2740861

Exhibit IM-21 (DLH-3)
Case No. U-18144

INDIANA MICHIGAN POWER COMPANY

REVISED TARIFF SHEET TO
REFLECT PROPOSED PSCR FACTOR

POWER SUPPLY COST RECOVERY FACTOR

(Continued from Sheet No. D-109.00)

Not more than 45 days following the last day of each billing month in which a power supply cost recovery factor has been applied to customers' bills, the Company shall file with the Commission a detailed statement for that month of the revenues recorded pursuant to the power supply cost recovery factor, the allowance for cost of power included in the base rates established in the latest Commission order for the Company, and the cost of power supply.

Not less than once a year and not later than 90 days after the end of the 12-month period covered by the Company's most recently authorized power supply cost recovery plan, a power supply cost reconciliation proceeding will be commenced to reconcile the revenues recorded pursuant to the power supply cost recovery factor and the allowance for cost of power included in the base rates as established by the Commission under the Company's most recent power supply cost recovery plan, among other things. The Company shall be required to refund to customers, or to credit to customers' bills any net amount, plus interest, determined to have been recovered which is in excess of the amounts properly expensed by the Company for power supply. The Company shall recover from customers any net amount, plus interest, by which the amount determined to have been recovered over the period covered was less than the amount determined to have been properly expensed by the Company for power supply.

Maximum allowable Power Supply Cost Recovery Factors approved by the Commission:

(1)	(2)	(3)	(4)
Billing Month	Total PSCR Costs (Mills/kWh)	PSCR Costs In Base Rates (Mills/kWh)	PSCR Factor Charge/(Credit) (Mills/kWh)
			(Col. 2 - Col. 3)
Jan. – Dec 2015	29.76	23.77	5.99
Jan. – Dec 2016	32.66	23.77	8.89

Should the Company apply a lesser factor than the above, or if the factor is later revised pursuant to Commission Orders or 1982 PA 304, the Company will notify the Commission if necessary and file a revision to the above list.

Actual Power Supply Cost Recovery factors billed pursuant to 1982 PA 304, Section 6j(9):

(1)	(2)	(3)	(4)	
Billing Month	Total PSCR Costs (Mills/kWh)	PSCR Costs In Base Rates (Mills/kWh)	PSCR Factor Charge/(Credit) (Mills/kWh)	
			(Col. 2 - Col. 3)	
Jan. – Dec 2015	29.76	23.77	5.99	
Jan. – Dec 2016	32.66	23.77	8.89	
Jan. – Dec 2016	34.27	23.77	10.50	N

ISSUED
BY PAUL CHODAK III
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR BILLS RENDERED
FOR THE 2017 PSCR PLAN YEAR

ISSUED UNDER AUTHORITY OF THE
MICHIGAN PUBLIC SERVICE COMMISSION
DATED
IN CASE NO. U-18144