STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF INDIANA MICHIGAN POWER COMPANY, AN INDIANA CORPORATION, FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A PHASE IN RATE ADJUSTMENT; AND FOR APPROVAL OF RELATED RELIEF INCLUDING: (1) REVISED DEPRECIATION RATES; (2) ACCOUNTING RELIEF; (3) INCLUSION IN RATE BASE OF QUALIFIED POLLUTION CONTROL PROPERTY AND CLEAN ENERGY PROJECT; (4) ENHANCEMENTS TO THE DRY SORBENT INJECTION SYSTEM; (5) ADVANCED METERING INFRASTRUCTURE; (6) RATE ADJUSTMENT MECHANISM PROPOSALS; AND (7) NEW SCHEDULES OF RATES, RULES AND REGULATIONS.	))))))))))))))	**CAUSE NO. 45235**

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

PUBLIC'S EXHIBIT NO. 5

TESTIMONY OF OUCC WITNESS

KALEB G. LANTRIP

August 20, 2019

Respectfully submitted,

Tiffany T. Murray
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Deputy Consumer Counselor

TESTIMONY OF OUCC WITNESS KALEB G. LANTRIP
CAUSE NO. 45235
INDIANA MICHIGAN POWER COMPANY

I. INTRODUCTION

Q: Please state your name, business address, and employment capacity.

A: My name is Kaleb G. Lantrip and my business address is 115 W. Washington St., Suite 1500 South, Indianapolis, Indiana 46204. I am employed as a Utility Analyst in the Indiana Office of Utility Consumer Counselor's ("OUCC") Electric Division. A summary of my educational background and experience is included in Appendix A attached to my testimony.

Q: What is the purpose of your testimony?

A: I address Indiana Michigan Power Company's ("I&M" or "Petitioner") proposed adjustments to its Resource Adequacy Rider ("RAR") and Off System Sales Margin Sharing/PJM Cost Rider ("OSS/PJM Rider"). I further address I&M's proposed regulatory accounting treatment for its EZ Bill Program. Ultimately, the OUCC recommends the Indiana Utility Regulatory Commission ("Commission"):

(1) Approve I&M's request to embed the test year level of non-FAC purchased power costs (i.e. capacity purchase expenses) in base rates and track incremental annual costs above and below this amount through the RAR, with I&M selling any excess capacity and passing back any annual capacity sales revenues to customers through the RAR;

(2) Approve continued tracking of OSS margins, but with 100% of all OSS margins greater than zero dollars allocated to ratepayers; and

(3) Deny I&M's request to treat EZ Bill Program profits and losses as above-the-line, and instead require I&M to treat all such costs below-the-line. In lieu of rendering a decision in this case on whether EZ Bill Program costs should be treated above or below the line, the OUCC recommends the accounting treatment of I&M's EZ Bill Program be addressed at the end of the three-year period, once data is available

to verify program costs and profitability, as well as customer participation, in order to determine whether recovery above-the-line is appropriate.

Q: Please describe the review and analysis you conducted to prepare your testimony.

A: I read I&M's petition, testimony, attachments and workpapers regarding its proposed revisions to its RAR and OSS/PJM Rider, and proposed regulatory accounting treatment of its EZ Bill Program. I reviewed I&M's responses to the OUCC's data requests for supporting documentation and explanation of information presented in this filing. I reviewed the Commission's Final Order dated May 30, 2018 in I&M's last base rate case, Cause No. 44967, which approved the Settlement Agreement between the parties to that Cause. Additionally, I reviewed testimonies and Commission Orders filed in Cause No. 45164 (RAR), dated February 26, 2019 and Cause No. 43774 PJM-9, dated January 29, 2019. I further reviewed the Commission's Order in Cause No. 45114 approving the Settlement Agreement, dated December 27, 2018, indicating I&M would propose regulatory accounting treatment for its EZ Bill Program in its case-in-chief at the time of its next base rate case.

Q: To the extent you do not address a specific item or adjustment, should that be construed to mean you agree with the Company's proposal?

A: No. Excluding any specific adjustments or amounts proposed by I&M from my testimony does not indicate my approval of those adjustments or amounts, but rather that the scope of my testimony is limited to the specific items addressed herein.

II. RESOURCE ADEQUACY RIDER

Q: Does I&M propose to continue its RAR?

A: Yes. I&M proposes to continue to track incremental non-FAC purchased power costs associated with its Unit Power Agreement ("UPA") with AEP Generating Company

("AEG") and Inter-Company Power Agreement with Ohio Valley Electric Corporation ("OVEC"), above and below an embedded base level of costs.

Q: Does I&M propose any changes to its RAR embedded base rate amount?

A: Yes. I&M proposes to embed in base rates its forecasted 2020 Test Year level of non-FAC purchased power costs in the amount of $190,132,242 (Total Company), and track incremental annual costs above and below this embedded amount through the RAR. The Indiana Jurisdictional amount would be approximately $134,336,700.[1]

Q: What support does I&M provide to continue tracking incremental RAR costs?

A: Mr. Williamson testifies, "[t]he RAR, in conjunction with the FAC, ensures that rates only reflect the actual cost of purchased power that I&M incurs to provide service to customers."[2] Mr. Williamson also testifies, "[t]he AEG and OVEC costs are significant in amount and subject to variability due to factors largely outside of I&M's control."[3] In I&M's response to The Kroger Company's Data Request ("DR") Set No. Kroger 4-03(c), I&M further indicated, "[t]he primary drivers of differences between the actual and forecasted expenses recovered through the RAR include the rate of magnitude of capital investment and operations and maintenance expenses."[4] In I&M's response to The Kroger Company's DR Set No. Kroger 4-03(d), I&M stated that "[u]npredictable drivers that may cause the costs recovered through the RAR to be higher or lower include an unforeseen extreme weather event or a change in the corporate tax rate."[4]

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[1] Calculated using the Indiana jurisdictional amount on Attachment JCD-1 for FERC 555 purchased power expense demand, in ratio to the RAR components of the total amount.
[2] I&M witness Andrew J. Williamson's Testimony, p. 54, lines 20-21.
[3] I&M witness Andrew J. Williamson's Testimony, p. 55, lines 2-4.
[4] *See* OUCC Attachment KGL-1, p. 1 of 2.

Q: Does the OUCC oppose I&M's request for continuance of its RAR?

A: No. Table 1 below provides actual purchased power non-FAC costs (total AEG and OVEC) for the period 2013-2018, as well as forecasted purchased power non-FAC costs for the period 2020-2025.[5] I&M's proposal to embed $190,132,242 (Total Company) in its base rates for non-FAC purchased power costs does not seem out of line with what it anticipates costs to be over the next three years (2020-2022). Additionally, embedding the forecasted Test Year level of purchased power non-FAC costs is consistent with the current treatment of purchased power non-FAC costs.

Table 1: Actual and Forecasted Purchased Power Costs

Total Company Purchased Power Non-FAC Costs	
Actual Purchased Power Costs 2013 (1)	$140,733,707
Actual Purchased Power Costs 2014 (1)	$143,870,910
Actual Purchased Power Costs 2015 (1)	$149,308,029
Actual Purchased Power Costs 2016 (1)	$144,776,159
Actual Purchased Power Costs 2017 (1)	$153,872,009
Actual Purchased Power Costs 2018 (1)	$161,285,252
Forecasted Purchased Power Costs 2020 (Test Year) (2)	$190,132,242
Forecasted Purchased Power Costs 2021 (3)	$189,511,000
Forecasted Purchased Power Costs 2022 (3)	$186,312,000
Forecasted Purchased Power Costs 2023 (3)	$120,409,000
Forecasted Purchased Power Costs 2024 (3)	$112,277,000
Forecasted Purchased Power Costs 2025 (3)	$113,646,000

(1) See Attachment KGL-2.
(2) I&M witness Andrew J. Williamson's Testimony, p. 55, lines 18-20
(3) See Attachment KGL-1, p. 2 of 2.

[5] Because 2019 consists of both actual and forecasted costs, in which a FERC Form 1 for the calendar year 2019 is not yet available, I did not include costs for 2019 in my analysis.

With regard to tracking incremental purchased power costs, the Commission has approved riders when costs are largely outside the utility's control, volatile in nature, and materially significant. The comparison of I&M's 2020 forecast test year purchase power costs with historical (2013-2018) and forecasted (2020-2025) purchased power costs differs from I&M's last base rate case, in which costs do appear to fluctuate across years. Additionally, tracking dollar-for-dollar incremental costs above and below the embedded base rate amount through an RAR ensures ratepayers are not paying for more capacity then required to comply with PJM's resource adequacy requirements. Further, without a RAR in place, ratepayers may not reap the benefits of excess capacity sales, as I&M has not proposed to embed an amount for capacity sales revenues.

Q: What does the OUCC recommend regarding I&M's request to continue its RAR and embed its 2020 forecasted Test Year level of purchase power costs in base rates?

A: The OUCC recommends the Commission approve I&M's request to embed non-FAC purchased power costs in the amount of $190,132,242 (Total Company) in base rates and track incremental annual costs above and below this amount through the RAR. Should I&M have excess capacity to sell as a result of the termination of municipal contracts and loss of wholesale load, or any other event that results in excess capacity, the OUCC recommends I&M sell the excess capacity and pass back any annual capacity sales revenues to customers through the RAR, as a means of reducing capacity purchases costs.

III. <u>OSS/PJM RIDER</u>

Q: Does I&M currently have an OSS/PJM Rider?

A: Yes. The Commission's Final Order in Cause No. 44967 approved I&M's request to merge its OSS and PJM Riders into one filing. I&M's annual OSS/PJM Rider: (1) passes back to customers 95% of the net benefits of OSS, with I&M retaining the other 5%; (2) tracks all the net costs charged to I&M by PJM for PJM Network Integration Transmission Service ("NITS") charges; and (3) tracks all other PJM charges (also referred to as non-NITS) above and below an embedded base rate level of costs.

Q: Does your testimony address all three parts of I&M's OSS/PJM Rider?

A: No. I address OSS margins and PJM non-NITS charges. OUCC witness Michael Gahimer addresses PJM NITS charges.

Q: Is I&M requesting to recover anything new through its OSS/PJM Rider?

A: Yes. I&M is requesting to begin tracking the cost of PJM Capacity Performance Insurance through its OSS/PJM Rider. This issue is addressed by Mr. Gahimer.

Q: Is I&M proposing any changes to the OSS margin tracking in its OSS/PJM Rider?

A: No. As stated by Mr. Williamson:

> I&M proposes to continue tracking OSS margins from $0, all positive and negative OSS margins through the Rider (with no margins embedded in base rates), and flow to customers 95% of these margins….
>
> Continuing to share 95/5 (customer/Company) of OSS margins is reasonable because it provides an incentive for the Company to maximize the benefits of OSS for both the Company and its customers. In addition, continued sharing recognizes the value of I&M's Commercial Operations organization, which is responsible for the PJM market bidding and hedging strategy for I&M's generation fleet, providing substantial value to I&M and its customers by optimizing I&M's OSS margins. Further, tracking OSS margins, and aligning OSS incentives, are even more important as the IMMDA contracts expire and there are additional opportunities for I&M and its customers to realize the benefits of OSS.[6]

Mr. Williamson further states on page 50, lines 6-7, that "OSS margins are largely contingent on PJM market energy prices which are variable due to a number of factors outside the control of the Company[.]"

[6] I&M witness Andrew J. Williamson, p. 49, lines 18-22 and p. 50, lines 1-4.

Q: Does the OUCC agree with I&M's requested continuance of the OSS portion of its OSS/PJM Rider?

A: The OUCC does not oppose continuing the OSS portion of the OSS/PJM Rider as proposed by I&M, with the exception of the 95/5 sharing. The OUCC recommends no sharing of OSS margins, and that customers receive 100% of all OSS margins greater than zero dollars. First, it is ratepayers who pay I&M's retail rates to support the operations and maintenance ("O&M") expenses and provide a return on rate base on the assets that create the opportunity for these sales. Therefore, I&M ratepayers should be the ones to benefit from such OSS margins.

Second, PJM plays the primary role in conducting OSS of I&M's excess generation, and it is I&M retail ratepayers who will pay the PJM administrative fees for this service. As a PJM market participant, I&M is required to offer all of its available electricity produced by its generating facilities into the PJM Market. An OSS automatically occurs when the amount of I&M generation for an hour exceeds the amount of system power consumed by its retail customers. Therefore, if OSS margins depend primarily on PJM's administration of unit dispatch and PJM's energy markets, then I&M has a limited role in its control of OSS margin outcomes and should not be entitled to receive OSS margin revenues. Likewise, if the OSS margins are handled through PJM's administration, and I&M passes through the administrative fees to ratepayers, then ratepayers should be the rightful beneficiaries of 100% of the OSS margins as well.

Third, the rates set in this Cause will incorporate the effect of I&M's 300 MW loss of municipal wholesale load, the cost of which will be borne by I&M's remaining customer classes. If these remaining customer classes are expected to bear the full brunt of I&M's

loss of this wholesale load, it is reasonable for these same ratepayers to enjoy the full benefit of any OSS margins profits.

Finally, although Mr. Williamson indicates I&M's Commercial Operations organization provides substantial value to I&M and its customers by optimizing I&M's OSS margins, maximizing the use of its generation facilities is something I&M should be doing as a part of normal utility business practice. Mitigating the costs to the customers that are paying for those generating facilities does not necessitate an incentive.

Q: Is I&M proposing to modify the recovery of non-NITS charges in its OSS/PJM Rider?

A: No. As stated by Mr. Williamson, I&M is proposing to "[e]mbed in base rates the forecasted Test Year level of all <u>non</u>-NITS PJM costs, and track any annual over/under variance from the embedded level[.]"[7]

Q: Does the OUCC oppose I&M's request to embed an amount for non-NITS costs and track any incremental amounts above or below the base level through the OSS/PJM Rider?

A: No. Although non-NITS costs do not appear to fluctuate significantly in projected years, the costs have fluctuated historically.[8] Therefore, continued tracking of non-NITS costs seems appropriate at this time. Additionally, embedding an amount in base rates for non-NITS costs is consistent with what the Commission approved in Cause Nos. 43306 and 44075. Further, embedding the forecasted Test Year level of all non-NITS costs is consistent with the current treatment of embedding the Test Year level of non-NITS costs.[9]

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[7] I&M witness Andrew J. Williamson's Testimony, p. 51, lines 3-5.
[8] See OUCC Attachment KGL-3.
[9] According to Mr. Williamson's testimony, p. 53, line 13, I&M proposes to embed the Test Year level of $49,356,916 (Indiana Retail) for non-NITS costs.

IV. EZ BILL PROGRAM ACCOUNTING

Q. What is I&M's EZ Bill Program?

A: I&M's EZ Bill Program is an annual voluntary program designed to allow eligible residential and commercial customers a flat rate monthly billing option based on data from the customer's average past usage, grossed up to estimated future costs, and adjusted for weather normalization. The Commission approved the EZ Bill Program as part of a Settlement Agreement in Cause No. 45114 on December 27, 2018.

Q: What accounting treatment did I&M propose for its EZ Bill program in Cause No. 45114?

A: In Cause No. 45114, I&M indicated that costs resulting from a customers' EZ Bill Program participation would be treated below-the line:

> Each month, I&M will calculate the difference between what each customer was billed under the EZ Bill program and what he or she would have been billed under the standard base rate tariff and applicable riders. This difference also appears as an "EZ Bill Adjustment" in the line item detail of the customers' monthly bill. The EZ Bill amount could be more or less than the standard tariff amount in any given month, for any given customer. This difference will be accounted for below the line for regulatory accounting purposes. Treating this difference below the line insulates non-participating customers from the risks of the EZ Bill program.[10]

However, I&M's proposal in Cause No. 45114 also requested recovery of program costs, such as solicitation, processing applications, usage modeling, fixed bill amount calculation, program monitoring, as well as administrative fees revenues, which I&M proposed to treat above-the-line. These above-the-line costs would be attributable to all customers regardless of whether they were eligible or even opted to participate in the program.[11] With

[10] *See* Cause No. 45114, I&M witness Brent E. Auer's Testimony, pp. 11-12.
[11] *See* Cause No. 45114, I&M witness Brent E. Auer's Testimony, p. 12, lines 18-23 and p. 13, lines 1-2.

regard to accounting treatment of the EZ Bill Program, I&M agreed in the Settlement to address it in its next base rate case, and to "separately account for all EZ Bill revenues, expenses, and other expenditures" until that time.[12]

Q: Did I&M propose accounting treatment for its EZ Bill Program in this proceeding?

A: Yes. Mr. Williamson states:

> I&M is proposing that EZ Bill Program costs and EZ Bill Program revenues be accounted for above the line. That is, I&M proposes that all EZ Bill Program costs and revenues be included in I&M's cost of service for purposes of setting rates.[13]

Q: Is I&M's proposed accounting treatment for the EZ Bill Program in this case different from what it proposed in Cause No. 45114?

A: Yes. In Cause No. 45114, I&M proposed that "profits and losses" from the EZ Bill Program be accounted for below-the-line, stating that below-the-line treatment insulates non-participating customers from the risks of the EZ Bill program. I&M further proposed in Cause No. 45114 that program costs and administrative fees revenues be treated above-the-line. I&M is now proposing to treat all costs associated with EZ Bill Program above-the-line.

Q: Why is I&M proposing this change to its requested accounting treatment?

A: Mr. Williamson states:

> [O]ver the long-run, EZ Program profits are expected to exceed losses, and overall EZ Bill Program revenues are expected to exceed what I&M's revenue would be under the otherwise applicable standard rates. Therefore, accounting for EZ Bill program revenue above the line is expected to benefit I&M's customers by offsetting I&M's cost of service and mitigating potential future rate increases.[14]

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[12] *See* the Settlement Agreement approved in the Commission's Order in Cause No. 45114, paragraph 6. *Also See* I&M witness Andrew J. Williamson's Testimony, p. 63, lines 21-25 and p. 64, lines 1-3.
[13] I&M witness Andrew J. Williamson's Testimony, p. 64, lines 6-9.
[14] I&M witness Andrew J. Williamson's Testimony, p. 65, lines 4-9.

Q: Is I&M proposing to recover actual costs associated with its EZ Bill Program in this case?

A: No. I&M is requesting regulatory accounting treatment in this case to include any EZ Bill revenues and expenses in its cost of service, but I&M is not proposing to reflect such costs (actual dollars) in its cost of service in this proceeding. Instead, I&M plans to include EZ Bill Program revenues and a representative level of EZ Bill costs above the line in its next base rate case proceeding.[15] Mr. Williamson further addresses deferring recovery of costs until I&M's next base rate case, stating:

> I&M's forecasted Test Year in this proceeding is based on an assumption that all customers will be served under standard rates and does not include any EZ Bill revenues. This is the most reasonable assumption at this time due to lack of data. However, in I&M's next base rate proceeding, I&M plans to include an assumed level of EZ Bill participation[.][16]

Q: Does the OUCC agree with I&M's proposed above-the-line accounting treatment for its EZ Bill Program?

A: No. Although I&M anticipates that EZ Bill Program profits will exceed losses, I&M has not indicated, nor has proof as to whether such net profits, and administrative fees revenues, will cover or exceed program costs. Mr. Williamson's testimony admits that the EZ Bill Program is in the preliminary stages and does not currently have any experience or data on the program, stating that "[c]ustomer program enrollment just recently began and to date there have been no EZ Bill program revenues to track."[17]

Mr. Williamson also states:

> I&M does not know how many customers will choose to participate in the EZ Bill program, and I&M does not yet have any experience with how EZ

[15] I&M witness Andrew J. Williamson's Testimony, p. 66, lines 15-18.
[16] I&M witness Andrew J. Williamson's Testimony, p. 65, line 19 and p. 66, lines 1-8.
[17] I&M Witness Andrew J. Williamson's Testimony, p. 65, lines 14-15.

> Bill revenues may differ from revenues under standard tariffs (i.e., I&M does not have any actual data on EZ Bill program "profits and losses").[18]

By including all associated EZ Bill Program costs above-the-line, I&M is socializing costs among all ratepayers, even though not all ratepayers will qualify for or utilize this optional program. Treating all EZ Bill Program costs above-the-line also puts non-participating customers at risk, should program costs (solicitation, processing applications, usage modeling and fixed bill amount calculation, and program monitoring) exceed program participation net profits and administrative fee revenues.

Further, the Settlement Agreement in Cause No. 45114 requires I&M to notify the OUCC of its plan to renew, modify or terminate the EZ Bill program and the ARP, no later than six months prior to the end of the third year of the program (i.e., no later than 30 months after I&M's initial enrollment period begins). Therefore, if costs associated with the EZ Bill Program are approved to be included in I&M's base rates, ratepayers could be paying for costs associated with a program that may not continue.

Q: What does the OUCC recommend regarding I&M's request to treat costs associated with its EZ Bill Program above-the-line?

A: The OUCC recommends the Commission deny I&M's request to treat costs associated with I&M's EZ Bill Program, including program costs and administrative fees, above-the-line. Instead, the OUCC recommends the Commission require I&M to treat all such costs below-the-line. Non-participating customers will be insulated from the risks of the EZ Bill program when its incremental expenses, losses, and profits are accounted for below-the-line.

[18] I&M Witness Andrew J. Williamson's Testimony, p. 65-66, lines 1-4.

In Cause No. 45114, I&M and the OUCC agreed that the EZ Bill Program would be offered for a three-year period during which I&M will provide an annual report documenting costs, customer information, profits or losses for the EZ Bill Program. Given the terms of that Agreement, in lieu of rendering a decision in this case on whether EZ Bill Program costs should be treated above or below the line, it would be appropriate to see the EZ Bill Program through to the end of the three-year period, and review I&M's data to verify program costs and profitability, as well as customer data and participation, in order to determine whether recovery above-the-line is appropriate in I&M's next rate case.

V. OUCC RECOMMENDATIONS

Q: What do you recommend regarding I&M's proposed RAR revisions?

A: The OUCC recommends the Commission approve I&M's request to embed non-FAC purchased power costs of $190,132,242 (Total Company) or approximately $134,336,700 (for the Indiana jurisdictional expense) in base rates and track incremental annual costs above and below this amount through the RAR. Should I&M have excess capacity to sell, the OUCC recommends I&M sell any excess capacity and pass back any annual capacity sales revenues to customers through the RAR, as a means of mitigating the capacity purchases costs to ratepayers.

Q: What do you recommend regarding I&M's proposed revisions to its OSS/PJM Rider?

A: The OUCC recommends the Commission approve I&M's request to continue tracking OSS margins, but with 100% of all OSS margins greater than zero dollars allocated to customers. The OUCC further recommends the Commission approve I&M's proposal to embed its 2020 Test Year level of PJM non-NITS costs, $49,356,916, (Indiana Retail), in base rates and track any incremental amounts above or below the base level through the

OSS/PJM Rider. Mr. Gahimer offers the OUCC's recommendations regarding I&M's proposed recovery of PJM NITS charges and the PJM Capacity Performance Insurance premium.

Q: What do you recommend regarding I&M's proposed EZ Bill Rider revisions?

A: The OUCC recommends the Commission deny I&M's request to treat costs associated with I&M's EZ Bill Program, including program costs and administrative fees, above-the-line, and instead recommends the Commission order I&M to treat all such costs below-the-line. Given the terms of the Cause No. 45114 Agreement, in lieu of rendering a decision in this case on whether EZ Bill Program costs should be treated above or below the line, it would be appropriate to see the EZ Bill Program through to the end of the three-year period, and review I&M's data to verify program costs and profitability, as well as customer data and participation, in order to determine whether recovery above-the-line is appropriate in I&M's next rate case.

Q: Does this conclude your testimony?

A: Yes.

APPENDIX A

Q: Please describe your educational background and experience.

A: I graduated from the Kelley School of Business of Indianapolis in 2014 with a Bachelor of Science in Business with majors in Accounting and Finance. I am licensed in the State of Indiana as a Certified Public Accountant. I attended the National Association of Regulatory Utility Commissioners ("NARUC") Spring 2018 Conference held by New Mexico State University.

Q: Have you previously testified before the Commission?

A: Yes.

Q: Please describe your duties and responsibilities at the OUCC.

A: I review Indiana utilities' requests for regulatory relief filed with the Indiana Utility Regulatory Commission ("Commission"). This involves reading testimonies of petitioners and intervenors, previous orders issued by the Commission, and any appellate opinions to inform my analyses. I then prepare and present testimony based on these analyses, and make recommendations to the Commission on behalf of Indiana utility consumers.

INDIANA MICHIGAN POWER COMPANY
THE KROGER COMPANY
DATA REQUEST SET NO. KROGER DR 4
IURC CAUSE NO. 45235

DATA REQUEST NO. Kroger 4-03

REQUEST

Please provide copies of the purchased power contracts included in the RAR for the UPA with AEG for a portion of the Rockport Plant and the Inter-Company Power Agreement with OVEC.

a. Please provide the actual costs incurred by I&M under these contracts for the most recent five years for which actual data is available.

b. Please provide the forecast of costs to be incurred by I&M under these contracts for the next five years after the test year.

c. Please identify all of the drivers that can cause the actual costs under these contracts to differ from the forecast?

d. Please provide examples of any unpredictable drivers that might cause costs to be lower or higher than expected.

e. Please describe the nature of these purchased power contracts.

RESPONSE

I&M objects to the request on the grounds and to the extent the request is overly broad and unduly burdensome, particularly to the extent that it seeks "all" of the drivers that can cause actual costs to differ from the forecast. I&M further objects to the request, and in particular subpart (a), to the extent the request seeks information that is publicly available from I&M's annual FERC Form 1 and is equally accessible to Kroger. Subject to and without waiver of the foregoing objections, I&M provides the following response.

The purchased power agreements are supplied as "Kroger 4-03 Attachment_1.pdf" and "Kroger 4-03 Attachment_2.pdf"

a. These values are provided in the Company's annual FERC Form 1 on pages 326 and 327 and the costs recovered through the RAR are included in column j (Demand Charges) . The Company's annual FERC Form 1 can be found here: https://elibrary.ferc.gov/idmws/search/fercadvsearch.asp

b. Please refer to "Kroger 4-03 Attachment_3.xlsx."

c. The primary drivers of differences between the actual and forecasted expenses recovered through the RAR include the rate and magnitude of capital investment and operations and maintenance expenses.

d. Unpredictable drivers that may cause the costs recovered through the RAR to be higher or lower include an unforeseen extreme weather event or a change in the corporate tax rate.

Indiana Michigan Power Company
Total Company Projected Demand Charges
Amounts in ($000)

	AEG [a]	OVEC
Year 2021	163,618	25,893
Year 2022	160,023	26,288
Year 2023	93,860	26,549
Year 2024	85,540	26,737
Year 2025	86,710	26,936

Note [a]: The following AEG related assumptions are reflected in this projection:
Assumes that Rockport Unit 2 operates through the end of PJM's planning year 5/23
Does not reflect NSR limit

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	AEP GENERATING COMPANY	RQ	AEG 1			
2	AEP Service Corporation	OS	17			
3	AEP Service Corporation	OS	20			
4	Ameren Energy Marketing	OS				
5	Associated Elect Cooperative	OS				
6	B.P. Energy Company	OS				
7	Beech Ridge Energy LLC	OS				
8	Buckeye Rural Electric Administration	OS				
9	CMS Marketing Svcs and Trading	OS				
10	DB Energy Trading LLC	OS				
11	Dynegy Power Marketing Inc.	OS				
12	EDF Trading North America LLC	OS				
13	Exelon Generation - Power Team	OS				
14	Fowler Ridge II Wind Farm LLC	OS				
	Total					

Cause No. 45235
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
5,532,653			108,821,464	142,696,757		251,518,221	1
5,420,180			7,029,441	174,657,708		181,687,149	2
60				3,266		3,266	3
			5,214			5,214	4
110				3,938		3,938	5
				-141,275		-141,275	6
				-22,575		-22,575	7
				458,242		458,242	8
			82,760			82,760	9
				53,348		53,348	10
			9,423			9,423	11
			135,475			135,475	12
				83,271		83,271	13
134,981				10,951,866		10,951,866	14
13,772,690			140,733,707	477,502,307		618,236,014	

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PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	AEP GENERATING COMPANY	RQ	AEG 1			
2	ADJUSTMENT	OS				
3	AEP SERVICE CORPORATION	OS	17			
4	AMEREN ENERGY MARKETING	OS				
5	B.P. ENERGY COMPANY	OS				
6	BEECH RIDGE ENERGY LLC	OS				
7	BUCKEYE RURAL ELECTRIC	OS				
8	CMS MARKETING SVCS AND TRADING	OS				
9	DB ENERGY TRADING LLC	OS				
10	DYNEGY POWER MARKETING INC.	OS				
11	EDF TRADING NORTH AMERICA LLC	OS				
12	EXELON GENERATION - POWER TEAM	OS				
13	FOWLER RIDGE II WIND FARM LLC	OS				
14	FOWLER RIDGE WIND FARM LLC	OS				
	Total					

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PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
5,850,980			119,115,751	149,220,849		268,336,600	1
				-127,163		-127,163	2
-6,613				1,238,503		1,238,503	3
			1,961			1,961	4
				1		1	5
				1,020		1,020	6
				3,506		3,506	7
			89,038			89,038	8
				-1,369,700		-1,369,700	9
			10,126			10,126	10
			5,185			5,185	11
				-154,102		-154,102	12
136,195				11,340,204		11,340,204	13
240,441				14,816,420		14,816,420	14
8,904,947			143,870,910	272,576,579		416,447,489	

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Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	AEP GENERATING COMPANY	RQ	AEG 1			
2	CITY OF WINCHESTER, IN	OS				
3	CMS MARKETING SVCS AND TRADING	OS				
4	DYNEGY POWER MARKETING INC.	OS				
5	EDF TRADING NORTH AMERICA LLC	OS				
6	FOWLER RIDGE II WIND FARM LLC	OS				
7	FOWLER RIDGE WIND FARM LLC	OS				
8	FRENCH PAPER	OS				
9	FT. WAYNE ELECTRIC JATC	OS				
10	HEADWATERS WIND FARM LLC	OS				
11	JP MORGAN VENTURES ENERGY CORP	OS				
12	OVEC POWER SCHEDULING	OS				
13	OVER / UNDER PJM EXP TRACKER	OS				
14	PJM INTERCONNECTION	OS				
	Total					

Cause No. 45235
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2015/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
4,356,078			120,248,808	111,859,152		232,107,960	1
				124,538		124,538	2
			96,396			96,396	3
			362			362	4
			-63,571			-63,571	5
141,950				11,949,652		11,949,652	6
256,775				16,129,579		16,129,579	7
2,153				63,089		63,089	8
1				35		35	9
645,858				27,137,341		27,137,341	10
			165,759			165,759	11
647,662			23,941,143	19,699,304		43,640,447	12
				17,817,394		17,817,394	13
2,079,018			4,919,132	93,471,041		98,390,173	14
8,450,553			149,308,029	313,697,424		463,005,453	

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	AEP GENERATING COMPANY	RQ	AEG 1			
2	CITY OF WINCHESTER, IN	OS				
3	CMS MARKETING SVCS AND TRADING	OS				
4	EDF TRADING NORTH AMERICA LLC	OS				
5	FOWLER RIDGE II WIND FARM LLC	OS				
6	FOWLER RIDGE WIND FARM LLC	OS				
7	FRENCH PAPER	OS				
8	FT. WAYNE ELECTRIC JATC	OS				
9	HEADWATERS WIND FARM LLC	OS				
10	JP MORGAN VENTURES ENERGY CORP	OS				
11	MIZUHO SECURITIES USA INC	OS				
12	OVEC POWER SCHEDULING	OS				
13	OVER/UNDER PJM EXP TRACKER	OS				
14	PJM INTERCONNECTION	OS				
	Total					

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PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
4,045,257			121,723,956	106,804,133		228,528,089	1
				99,778		99,778	2
			42,232			42,232	3
			-37,754			-37,754	4
131,394				11,311,661		11,311,661	5
233,221				15,013,090		15,013,090	6
1,741				51,024		51,024	7
1				32		32	8
670,521				28,341,438		28,341,438	9
			5,172			5,172	10
				36,000		36,000	11
743,027			22,876,117	21,143,535		44,019,652	12
				4,054,840		4,054,840	13
2,808,404			166,436	107,191,218		107,357,654	14
8,961,708			144,776,159	309,792,310		454,568,469	

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	AEP GENERATING COMPANY	RQ	AEG 1			
2	CITY OF WINCHESTER, IN	OS				
3	FOWLER RIDGE II WIND FARM LLC	OS				
4	FOWLER RIDGE WIND FARM LLC	OS				
5	FRENCH PAPER	OS				
6	FT. WAYNE ELECTRIC JATC	OS				
7	HEADWATERS WIND FARM LLC	OS				
8	ICE TRADE VAULT LLC	OS				
9	MIZUHO SECURITIES USA INC	OS				
10	OVEC POWER SCHEDULING	OS				
11	OVER/UNDER PJM EXP TRACKER	OS				
12	PJM INTERCONNECTION	OS				
13	RANDOLPH SCHOOLS	OS				
14	WILDCAT WIND FARM	OS				
	Total					

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2017/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
3,823,206			127,733,065	96,166,427		223,899,492	1
				118,742		118,742	2
124,869				10,868,939		10,868,939	3
208,368				13,647,550		13,647,550	4
1,131				33,583		33,583	5
1				29		29	6
724,311				31,568,522		31,568,522	7
				12,600		12,600	8
				14,400		14,400	9
937,620			26,138,944	24,381,550		50,520,494	10
				-48,010,285		-48,010,285	11
2,270,707				94,239,229		94,239,229	12
				44,475		44,475	13
234,960				17,389,534		17,389,534	14
8,325,176			153,872,009	240,475,387		394,347,396	

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	AEP GENERATING COMPANY	RQ	AEG 1			
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3	FOWLER RIDGE II WIND FARM LLC	OS				
4	FOWLER RIDGE WIND FARM LLC	OS				
5	FRENCH PAPER	OS				
6	FT. WAYNE ELECTRIC JATC	OS				
7	HEADWATERS WIND FARM LLC	OS				
8	ICE TRADE VAULT LLC	OS				
9	OVEC POWER SCHEDULING	OS				
10	OVER/UNDER PJM EXP TRACKER	OS				
11	OVER/UNDER RESOURCE ADEQUACY	OS				
12	PJM INTERCONNECTION	OS				
13	RANDOLPH SCHOOLS	OS				
14	WILDCAT WIND FARM	OS				
	Total					

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PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
4,162,940			133,411,432	104,496,745		237,908,177	1
				144,774		144,774	2
118,832				10,832,568		10,832,568	3
209,512				14,226,557		14,226,557	4
1,190				32,210		32,210	5
1				31		31	6
650,380				28,695,579		28,695,579	7
				11,875		11,875	8
959,125			26,555,612	23,684,683		50,240,295	9
				28,782,903		28,782,903	10
			1,318,208			1,318,208	11
1,846,868				95,625,043		95,625,043	12
				16,741		16,741	13
309,127				18,631,027		18,631,027	14
8,257,977			161,285,252	325,180,791		486,466,043	

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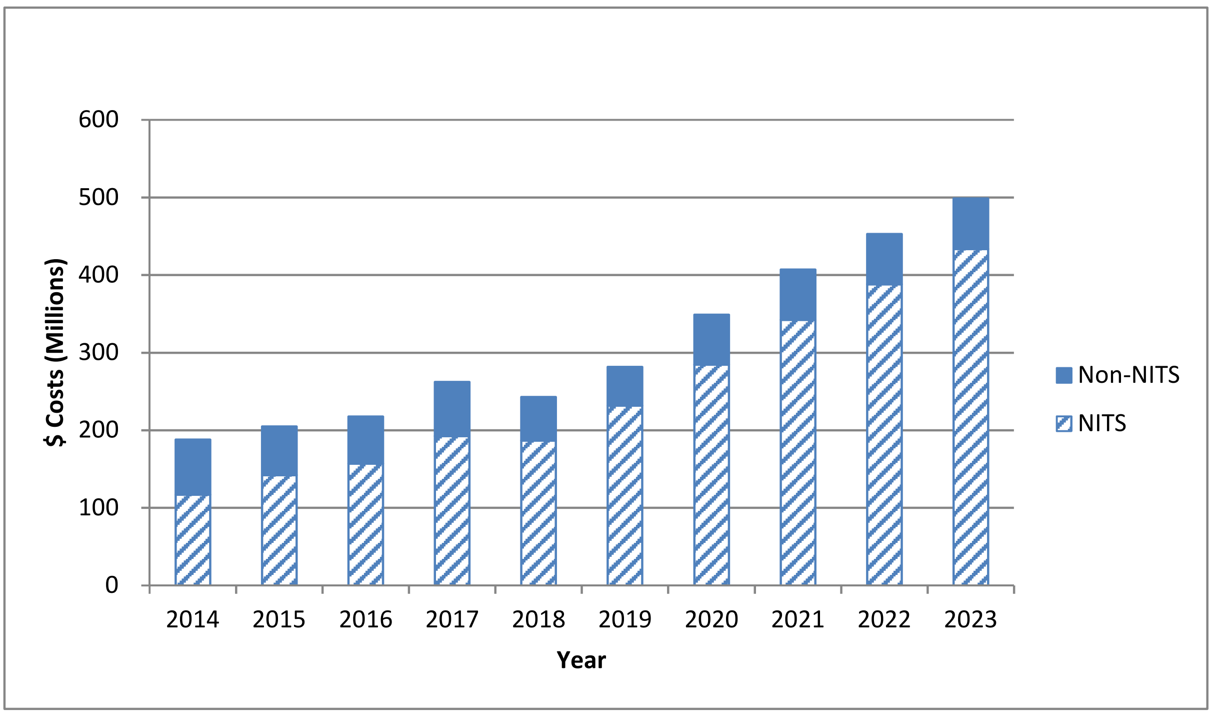
Year	NITS	Non-NITS	Total	
2014	117,044,153	71,140,567	188,184,720	
2015	141,987,002	62,922,708	204,909,710	
2016	156,934,855	60,652,441	217,587,296	Actuals
2017	192,730,391	69,471,386	262,201,777	
2018	186,841,953	55,833,139	242,675,093	
2019	231,621,979	49,996,514	281,618,493	
2020	284,673,478	64,399,751	349,073,228	
2021	342,328,559	64,993,322	407,321,881	Forecast
2022	388,278,024	64,773,646	453,051,670	
2023	433,375,060	65,164,332	498,539,392	

Figure KA-2



AFFIRMATION

I affirm, under the penalties for perjury, that the foregoing representations are true.

Kaleb G. Lantrip

Kaleb G. Lantrip
Utility Analyst II
Indiana Office of Utility Consumer Counselor

Cause No. 45235
Indiana Michigan Power Company

8-20-19

Date

CERTIFICATE OF SERVICE

Indiana Office of Utility Consumer Counselor Public's Exhibit No. 5 Testimony of OUCC Witness Kaleb G. Lantrip has been served upon the following parties of record in the captioned proceeding by electronic service on August 20, 2019.

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