STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

JOINT PETITION OF INDIANA MICHIGAN POWER COMPANY (I&M) AND AEP GENERATING COMPANY (AEG) FOR CERTAIN DETERMINATIONS WITH RESPECT TO THE COMMISSION'S JURISDICTION OVER THE RETURN OF OWNERSHIP OF ROCKPORT UNIT 2 AND FOR THE CREATION OF A SUBDOCKET TO ADDRESS ASSOCIATED ACCOUNTING AND RATEMAKING MATTERS, OR IN THE ALTERNATIVE ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY.	CAUSE NO. 45546

IURC
INTERVENOR'S -WVPA
EXHIBIT NO. 1
9-10-21 AT
DATE REPORTER

PUBLIC VERSION

VERIFIED DIRECT TESTIMONY
OF
MATTHEW MOORE

On behalf of Intervenor

WABASH VALLEY POWER ASSOCIATION, INC.
d/b/a
WABASH VALLEY POWER ALLIANCE

WVPA Exhibit 1

July 29, 2021

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A1. My name is Matthew Moore, and my business address is the offices of Wabash Valley Power Association, Inc., 6702 Intech Boulevard, Indianapolis, Indiana 46278.

Q2. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A2. I am employed by Wabash Valley Power Association, Inc. dba Wabash Valley Power Alliance ("Wabash Valley") as its Executive Vice President - Risk and Resource Portfolio.

Q3. PLEASE STATE YOUR EDUCATIONAL BACKGROUND.

A3. I graduated from Purdue University in 1997 with a degree in Industrial Engineering Technology and earned a Master of Business Administration from Indiana State University in 2017.

Q4. PLEASE STATE YOUR PROFESSIONAL EXPERIENCE.

A4. I began my professional career at the Alliance of Cooperative Energy Services ("ACES") in 2001 as an Hourly Trader. Over the course of 19 years at ACES, I held various roles of increasing responsibilities including Portfolio Director, Executive Director of Portfolio Strategy and Vice President of Regulatory and Reliability Services. I joined Wabash Valley as the Executive Vice President - Risk and Resource Portfolio in September of 2020.

Q5. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS EXECUTIVE VICE PRESIDENT – RISK AND RESOURCE PORTFOLIO.

A5. As Executive Vice President - Resource Portfolio and Risk, my duties include direction of the Power Supply department in acquiring, managing and delivering the power requirements of the Wabash Valley member systems, long-term strategy and short-term optimization of Wabash Valley's portfolio of resources, as well as managing enterprise risk processes and procedures. In my role as Executive Vice President - Resource Portfolio and Risk, I am actively involved in procuring, on behalf of Wabash Valley, the electric energy, electric capacity and natural gas to meet Wabash Valley members' load requirements in the Midcontinent Independent System Operator ("MISO") and PJM Interconnection, LLC ("PJM") electric energy and capacity markets and the national natural gas markets.

Q6. BREIFLY DESCRIBE THE PURPOSE OF YOUR TESTIMONY ON BEHALF OF WABASH VALLEY IN THIS PROCEEDING?

A6. The purpose of my testimony in this proceeding is to provide the reasons why Wabash Valley is opposed to the Commission authorizing Indiana Michigan Power Company ("I&M") and AEP Generating Company ("AEG") to purchase the Rockport Unit 2 when the current leases between the Unit's owners and I&M/AEG expire at the end of 2022.

Q7. PLEASE DESCRIBE WHAT WABASH VALLEY IS AND WHAT IT DOES.

A7. Wabash Valley is an Indiana nonprofit mutual benefit corporation that its members formed in 1963. Wabash Valley is a generation and transmission ("G&T") cooperative whose members, with two exceptions, are electric distribution cooperatives that serve their consumer-members at retail in rural areas of the states of Indiana, Illinois and Missouri.[1] Wabash Valley's primary mission is to supply all-requirements electric energy

[1] Wabash Valley currently has twenty-five members who are both the owners and customers of Wabash Valley. Twenty-three members are not-for-profit distribution cooperatives that provide retail electric energy to their consumer-members across rural areas in Indiana, Illinois and Missouri. These twenty-three members serve nearly 300,000 residential customers and about 19,000 commercial and industrial customers. The other two members are a Wabash Valley subsidiary, Wabash Valley Energy Marketing, Inc. ("WVEM"), and J. Aron & Company, Inc. ("J.Aron"), neither of which has retail load-serving obligations.

at wholesale to its distribution cooperative members for resale to their consumer-members. Consistent with prudent management and sound fiscal policy, Wabash Valley provides all of the wholesale power requirements of its distribution cooperative members at cost-based rates to meet the members' energy needs.

Q8. PLEASE PROVIDE A BRIEF OVERVIEW OF THE SIZE OF THE MEMBER LOAD THAT WABASH VALLEY SERVES AND THE RESOURCES IT HAS TO PROVIDE THAT WHOLESALE SERVICE.

A8. Wabash Valley members' aggregate annual peak demand is about 1,565 MW, and their aggregate annual energy requirements are approximately 7,341,000 MWh (excluding retail industrial loads that are served at market-based pass-through rates). Wabash Valley meets its members' capacity and energy needs through a portfolio of owned and contracted power supply resources. Wabash Valley owns approximately 1,100 MW of generating capacity in Indiana and Illinois and meets the remainder of its members' needs through multiple purchase power agreements. These purchase agreements have varying terms, with the longest contract extending to 2050.

Q9. PLEASE PROVIDE A BRIEF OVERVIEW OF HOW WABASH VALLEY DELIVERS WHOLESALE POWER TO ITS MEMBERS.

A9. Wabash Valley has a limited amount of transmission assets, is a transmission owner and transmission customer of Midcontinent Independent System Operator ("MISO"), a transmission customer of PJM Interconnection LLC ("PJM") and a market participant in both MISO and PJM. Wabash Valley does not provide or control access to transmission service but generally purchases transmission service to deliver power to its members under the MISO and PJM Open Access Transmission Tariffs and certain grandfathered agreements under those tariffs.

Q10. PLEASE EXPLAIN HOW WABASH VALLEY IS REGULATED.

A10. Wabash Valley is subject to the general jurisdiction, including rate regulation, of the Federal Energy Regulatory Commission ("FERC"), but remains subject to the jurisdiction of the Indiana Utility Regulatory Commission ("IURC" or "Commission") for a variety of matters including, but not limited to, integrated resource planning, certificates of public convenience and necessity ("CPCN") for the construction or purchase of generation facilities under Ind. Code § 8-1-8.5 ("CPCN Statute") and the issuance of long-term debt. All of Wabash Valley's Indiana members have withdrawn from the Commission's jurisdiction.

Q11. PLEASE EXPLAIN WHY WABASH VALLEY HAS INTERVENED IN THIS PROCEEDING.

A11. Wabash Valley has certain delivery points located within the AEP Load Zone that serve its Indiana members that are currently served by I&M under an all-requirements cost-based wholesale power purchase agreement with Wabash Valley that runs through December 31, 2033 (the "Load Following Agreement"). The annual peak load for Wabash Valley's members under the Load Following Agreement is approximately 140 MW or approximately 3.6% of I&M's total capacity requirements. The terms of the Load Following Agreement subject Wabash Valley to a proportional share of I&M's system costs as recorded in I&M's FERC Form 1 together with a return on common equity. Decisions by I&M, AEG and the Commission in this proceeding regarding I&M's and AEG's purchase of Rockport Unit 2 directly impacts I&M's costs under

I&M's wholesale contracts (e.g. the Load Following Agreement) which directly impacts Wabash Valley's total cost to serve its members.

Q12. PLEASE STATE YOUR UNDERSTANDING OF WHAT APPROVALS I&M AND AEG ARE REQUESTING FROM THE COMMISSION IN THIS PROCEEDSING REGARDING THE PURCHASE OF ROCKPORT UNIT 2.

A12. In their Verified Joint Petition, I&M and AEG are asking the Commission to grant them approval to purchase Rockport Unit 2 without obtaining a CPCN as required under the CPCN Statute and deferring any decision on whether I&M can include the costs of owning and operating Rockport Unit 2 in its Indiana jurisdictional cost of service rates to a subsequent proceeding. On July 1, 2021, the Indiana Office of Utility Consumer Counselor ("OUCC"), Citizens Action Coalition of Indiana, Inc., Sierra Club, I&M Industrial Group, City of Marion, Indiana, Marion Municipal Utilities and the City of Fort Wayne, Indiana ("Consumer Parties") filed a Motion to Dismiss I&M and AEG's Verified Joint Petition in this proceeding for failure to comply with the requirements of the CPCN Statute, such as demonstration of necessity and consideration of alternatives for servicing customers. The Consumer Parties' Motion to Dismiss is still pending before the Commission.

Q13. PLEASE EXPLAIN YOUR GENERAL UNDERSTANDING OF THE TERMS OF THE TRUST INTEREST PURCHASE AGREEMENTS ("TIPAs") THAT I&M AND AEG HAVE ENTERED INTO WITH THE OWNERS OF ROCKPORT UNIT 2.

A13. On April 20, 2021, I&M and AEG entered into TIPAs with each of the owners of Rockport Unit 2 (the "Sellers") to purchase their beneficial interests under two Trusts that directly own Rockport Unit 2. Upon Closing on the proposed transaction, I&M and AEG would indirectly own Rockport Unit 2 through their ownership of 100% of the beneficial interests in each of the Trusts. I&M and AEG have stated in their Joint Verified Petition in this proceeding that upon consummation of the proposed transaction, they would terminate each of Trusts and each directly own 50% of the Rockport Unit 2. I&M and AEG filed one of the TIPAs under seal in this proceeding as Petitioner's Attachment TLT-2 (Confidential).

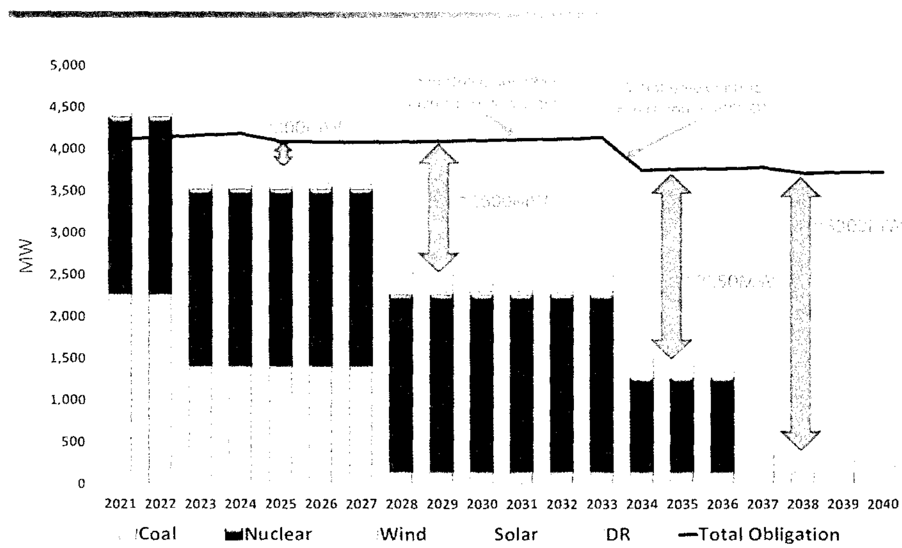
Under the TIPAs, the aggregate purchase price for Rockport Unit 2 is $115,000,000 and the Closing is scheduled to take place on December 7, 2022.

One of the conditions precedent to Closing is that all required governmental consents for the proposed transaction, including the approval of FERC and the IURC, be obtained. The TIPAs also provide that if the required governmental approvals are not obtained by December 16, 2021, either the Sellers or I&M/AEG may terminate the TIPAs upon notice to the other parties.

Q14. WHAT IS YOUR UNDERSTANDING OF I&M'S CAPACITY POSTION THROUGH 2040?

A14. The below publicly available chart that was provided during I&M's current integrated resource planning ("IRP") process shows I&M's capacity obligations and capacity position for the period 2021 through 2040.

Going-in PJM Capacity Position – (UCAP MW)



Q15. DOES I&M AND AEG NEED TO PURCHASE ROCKPORT UNIT 2 IN ORDER TO MEET I&M'S CAPACITY REQUIREMENTS TO SERVE IT NATIVE LOAD AND THE LOAD OF ITS WHOLESALE CUSTOMER, SUCH AS WABASH VALLEY THROUGH 2028?

A15. No. During the period 2023 and 2027, I&M's capacity shortfall is by its own calculation only about 300MWs. It is not clear why I&M (and AEG) would purchase Rockport Unit 2, a 1,300MW resource, to meet an approximate 300MW capacity shortfall. Additionally, I&M is currently working through its IRP process and that process will not be completed until later in 2021. It is my understanding from publicly available information that I&M plans to add considerable amounts of renewable resources to its portfolio between 2021 through 2030. What is not clear is the timing related to when these renewable resources will be added to I&M's portfolio. If I&M incorporates the 450MW of solar (Mammoth Solar I) that is scheduled to be in commercial operation by the second quarter of 2023 into its portfolio, those resources will address most of the current forecasted capacity deficit through 2027. I&M has also stated that they only plan to utilize Rockport Unit 2 as a capacity resource as compared to an energy resource. What I&M and AEG have not done in this proceeding is to appropriately evaluate cost-effective alternatives for meeting I&M's capacity requirements through 2028 rather than purchase Rockport Unit 2.

Q16. WHAT ARE THE REASONS WHY WABASH VALLEY IS OPPOSED TO I&M AND AEG PURCHASING ROCKPORT UNIT 2 AT THE END OF THE CURRENT LEASE TERM (i.e. December 31, 2022)?

A16. First, the TIPAs explicitly provide that I&M and AEG will not be responsible for compliance costs under the Effluent Limitation Guidelines (ELG") for Rockport Unit 2, estimated to be approximately $50 million, since the TIPAs explicitly grant I&M/AEG the sole and exclusive right to avoid such costs by notifying the United States Environmental Protection Agency ("US EPA") and the Indiana Department of Environmental Management ("IDEM") by October 13, 2021 that the unit will be retired by the end of 2028. That election if timely made is binding on the Sellers under the terms of the TIPAs irrespective of whether the TIPAs are terminated because all required governmental approvals have not been obtained. If the Sellers want to change that ELG election in order to operate the unit beyond 2028, all cost associated with that change, including ELG compliance costs, are explicitly at the Sellers' sole cost and expense pursuant to the TIPAs.

Second, the TIPAs expressly provides that if the TIPAs are terminated, the Sellers will enter into a "Bridge Agreement" that allows I&M to utilize and purchase the capacity of Rockport Unit 2 for any Delivery Year that I&M has included Rockport Unit 2 as part of its PJM Fixed Resource Requirement ("FRR") Alternative plan. Under the TIPAs, if I&M purchases such Rockport Unit 2 capacity, I&M has agreed to compensate the Sellers at the PJM Base Residual Auction ("BRA") clearing price for any such capacity. This provision will permit I&M at the least to meet its PJM capacity obligations at minimal costs through the 2022/2023 and 2023/2024 Delivery Years ("DY").

Third, although the cost associated with the purchase of Rockport Unit 2 is considerably lower than current lease costs, the cost of alternatives (discussed below) will be substantially less than the cost of purchasing and owning Rockport Unit 2.

Fourth, it is my understanding that I&M will be obligated under the Unit Purchase Agreement with AEG to purchase all of AEG's capacity and energy entitlement from Rockport Unit 2 and that all such costs will flow through I&M's FERC Form 1. Since Wabash Valley is obligated to pay for approximately 3.6% of I&M's system costs under the Load Following Agreement, the decision to allow I&M/AEG to purchase Rockport Unit 2 will have a direct impact on Wabash Valley's costs and the rates it charges is members and their retail customers.

Q17. WHY DO YOU BELIEVE I&M WILL HAVE OR CAN REASONABLY OBTAIN SUFFICIENT CAPACITY RESOURCES AT LOWER COSTS TO MEET IT RESOURCE REQUIREMENT THROUGH 2028 WITHOUT I&M AND AEG PURCHASEING ROCKPORT UNIT 2?

A17. <u>Bridge Agreement for Rockport Unit 2 Capacity</u>

The Bridge Agreement agreed upon in the TIPAs (Exhibit H of the TIPAs and also shown below) states that I&M will compensate the Sellers ("Owner Participants") for any year that I&M has elected to include Rockport Unit 2 in its FRR plan for each applicable DY.

Bridge Agreement Terms

To the extent that (x) I&M and/or AEG elect (or have elected) to include the capacity from Rockport Unit 2 in a Fixed Resource Requirement ("FRR") Alternative plan for any PJM "Delivery Year" (as specified in PJM's rules, a "DY") with respect to any such election made prior to earlier of the Closing or the termination of this Agreement in accordance with its terms, and (y) thereafter the Closing does not occur for whatever reason (and this Agreement is terminated in accordance with its terms without such Closing having occurred), then in connection with the surrender by I&M and AEG of the Undivided Interest to the Owner Participants pursuant to Section 5 of the Lease on the Lease Termination Date and the Lessor or another third party shall become the "Participant" under the Unit 2 Operating Agreement (together, the "Surrender"). I&M and AEG will compensate the Owner Participants for such inclusion in such FRR Alternative plan for each applicable DY. This compensation will equal the product of (a) the full unforced capacity ("UCAP") of Rockport Unit 2 as included in such FRR Alternative plan, (b) the number of days in the DY in which the Owner Participants are entitled to the output of Rockport Unit 2 (which shall be equal to 175 days in the 2022/23 DY, and 365 days in any subsequent DY), and (c) the PJM "Base Residual Auction" (or "BRA") clearing price for the "Rest of RTO Locational Delivery Area" (as defined by PJM) for the applicable DY. In addition, subject to compliance with the applicable Transaction Documents with respect to such Surrender, including ongoing arrangements under the Unit 2 Operating Agreement and the Ground Lease, so long as Rockport Unit 2 is not retired or shut down prior to or during the applicable DY, I&M and AEG also will be responsible for any PJM non-performance assessment, charge or penalty related to Rockport Unit 2 during a DY in which Rockport Unit 2's UCAP is included in such applicable FRR plan.

I&M has already submitted its FRR plan for the 2022/2023 DY which includes Rockport Unit 2 as a resource. The FRR plan for the 2023/2024 DY is due to PJM by November 1, 2021 since the BRA for that DY is scheduled for December 1, 2021. I&M will have to submit its FRR plan for the 2023/2024 DY prior to that deadline and has the contractual right under the TIPAs to include Rockport Unit 2 as a capacity resource in its FRR plan. As such I&M could conservatively expect to purchase capacity associated with Rockport Unit 2 for the 2022/2023 DY and the 2023/2024 DY for around $88/MW-Day, which is the average clearing price for the last three PJM BRAs.

Renewable Additions – Timing & Capacity Credit

The below table is publicly available information representing I&M's projections of renewable additions that has been developed as part of I&M's current IRP process.

Projected Regulated Resource Additions

SOLAR ADDITIONS (MW)

Company	2021 – 2025	2026 – 2030	Total	Prior Total (2020 EEI)	Incremental Solar Opportunity
APCo	210	450	660	710	(50)
I&M	450	450	900	1,300	(400)
KPCo	150	300	450	273	177
PSO	1,350	2,250	3,600	1,211	2,389
SWEPCO	300	-	300	300	-
Total	**2,460**	**3,450**	**5,910**	**3,794**	**2,116**

WIND ADDITIONS (MW)

Company	2021 – 2025	2026 – 2030	Total	Prior Total (2020 EEI)	Incremental Wind Opportunity
APCo	1,800[1]	-	1,800[1]	600	1,200[1]
I&M	800	-	800	750	50
KPCo	500	500	1,000	200	800
PSO	1,975[2]	1,300	3,275[2]	1,275[2]	2,000
SWEPCO	2,310[2]	1,500	3,810[2]	1,410[2]	2,400
Total	**7,385[2]**	**3,300**	**10,685[2]**	**4,235[2]**	**6,450**

I&M is projecting to add 450MW of solar and 800MW of wind between now and 2025. During the 2021-2025 period, as I&M includes renewable resources into its resource portfolio, the projected capacity shortfall position will be reduced. Renewable capacity does not receive full capacity credit due to the intermittency of production. Taking this fact into account, conservatively I&M will receive capacity credit of 305MW if they add 450MW of solar and 800MW of wind to their portfolio, assuming a 50% capacity credit for solar and 10% capacity credit for wind.

<u>Wholesale Contracts Modifications</u>

I&M could elect to work with their wholesale customers to reduce their capacity obligations. According to I&M publicly available information, they have 400MW of capacity obligations with wholesale customers that will end in 2033. Negotiating to amend or end those wholesale capacity and energy obligations could reduce I&M's capacity requirements now through 2033 and avoid making long-term capacity commitments for load obligations that will go away after 2033 when I&M's wholesale contracts expire. Negotiations with the wholesale customers to equitably reduce each party's contractual obligations to supply and purchase energy and capacity could reduce the need for medium term capacity resources while ensuring that I&M and its retail customers are made financially whole and do not result in its retail customers paying for stranded generation resources after the wholesale contracts expire.

Q18. BASED ON YOUR ANALYSIS, WHAT ARE THE ANNUAL FIXED COSTS OF THE VARIOUS ALTERNATIVES TO I&M/AEG PURCHASING ROCKPORT UNIT 2?

A18. I&M will incur approximately $24 million in annual fixed O&M costs[2] and an estimated $30 million in costs associated with owning Rockport Unit 2[3] if purchased assuming that I&M's revenue requirements are similar to AEG's cost for 50% ownership of the plant. I assume the total annual cost are $54 million for I&M to own and purchase 100% of the Rockport 2 plant. Considering the fact that I&M only needs a portion of the capacity to manage their capacity shortfall, $54 million annually seems to be a high cost alternative to other potential options.

Alternatively, I&M could utilize the Bridge Agreement and pay the Owner Participants for the purchased capacity at the PJM BRA clearing price. If I&M purchased all 1300 MW of capacity from Rockport Unit 2 under Bridge Agreement, 900 MW more than needed cover its capacity deficit in the 2023/2024 DY, the annual cost would conservatively be $41.8 million assuming $88/MW-Day. However, if I&M elected to purchase just 400 MW Rockport Unit 2 to meet its annual capacity shortfall, the annual cost would be $12.8 million. Even assuming a severe scenario where the PJM

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[2] See Exhibit WV-002 – I&M/AEG Response to FW/Marion DR 2-01, Confidential Attachment 4.
[3] See Exhibit WV-003 – I&M/AEG Response to OUCC DR 2-12

BRA cleared at the highest historical clearing price of $174.29/MW-Day (2010/2011 DY), the annual cost of 400MW of capacity from Rockport Unit 2 would be $25.5 million, which is still lower than the annual cost of owning and operating the resource. This strategy would allow layering in of renewable resources to cover capacity shortfall through 2028.

Q19. DO YOU BELIEVE THAT I&M NEEDS ROCKPORT UNIT 2 FOR SYSTEM RELIABILITY.

A19. I&M's witnesses have asserted that Rockport Unit 2 is or may be needed to support system reliability. However, I&M has either not conducted or not provided any system reliability studies, either internal or from PJM, to demonstrate that Rockport Unit 2 must continue to be operated through 2028 to support system reliability. Without such evidentiary support, the Commission should not credit such assertions by I&M that I&M/AEG need to purchase Rockport Unit 2 and operate it through 2028.

Q20. PLEASE STATE ANY CONCLUDING REMARKS.

A20. Based on the record evidence in this proceeding, the Commission should not approve the purchase of Rockport Unit 2 by I&M and AEG because there are less costly alternatives for I&M to cover it capacity shortage between now and the end of 2028.

Q21. DOES THIS CONCLUDE YOUR TESTIMONY?

A21. Yes.

Cause No. 45546
WVPA Exhibit 1

VERIFICATION

The undersigned affirms under the penalties of perjury that the facts stated in the foregoing testimony are true to his best information and belief.

Matthew Moore

INDIANA MICHIGAN POWER COMPANY
FORT WAYNE AND MARION
DATA REQUEST SET NO. FW/MARION DR 2
IURC CAUSE NO. 45546

DATA REQUEST NO FW/Marion 2-01

REQUEST

Please provide five-years (2016-2020) of historical data and eight-years (2021-2028) of projected data on an annual basis for the following data for Rockport Unit 2:

a) Operating and maintenance costs by FERC Account;
b) Fuel and fuel handling related costs;
c) Consumable costs including any reagents;
d) Capital expenditures;
e) Gross generation (MWh);
f) Net Generation (MWh);
g) Net Capacity Factor (%);
h) Hours Available (Hours);
i) Availability factor (%);
j) Scheduled outage factor (%);
k) Forced outage factor (%); and
l) Net Unit Heat Rate (Btu/kWh).

RESPONSE

I&M objects to the request on the grounds and to the extent the request seeks information that is outside the scope of this proceeding and not reasonably calculated to lead to the discovery of relevant or admissible evidence. I&M further objects to the request on the grounds and to the extent the request seeks information that is confidential, proprietary, competitively sensitive, and/or trade secret. Without waiving these objections, the Company responds as follows:

See FW 2-01 Attachment 1 for the historical Gross Generation, Net Generation, Net Capacity Factor, Hours Available, Availability Factor, Scheduled Outage Factor, Forced Outage Rate, and Net Unit Heat Rate for Rockport Unit 2.

Please see FW 2-01 CONFIDENTIAL Attachment 2 for the forecasted Fuel Cost, Fuel handling, Consumable cost, Net Generation, Net Capacity Factor, Hours Available, Availability Factor, Scheduled Outage Factor, Forced Outage Rate, and Net Unit Heat Rate for Rockport Unit 2. Please note that the 2021 forecast reflects the remainder of the year, June-December 2021. The Company does not forecast Gross Generation.

See FW 2-01 Attachment 3 for historical O&M expenses for Rockport Unit 2. See FW 2-01 CONFIDENTIAL Attachment 4 for forecasted O&M expenses for Rockport Unit 2.

See FW 2-01 Attachment 5 for historical Fuel and Consumables costs for Rockport Unit 2.

INDIANA MICHIGAN POWER COMPANY
FORT WAYNE AND MARION
DATA REQUEST SET NO. FW/MARION DR 2
IURC CAUSE NO. 45546

See FW 2-01 Attachment 6 for historical capital expenditures for Rockport Unit 2, and FW 2-01 CONFIDENTIAL Attachment 7 for forecasted capital expenditures for Rockport Unit 2.

Indiana Michigan Power Company
Cause No. 45546
Response to FW 2-01 Attachment 4 (Confidential)

CONFIDENTIAL - EXCLUDED FROM PUBLIC ACCESS PER INDIANA RULES ON ACCESS TO COURT RECORDS RULE 5 (FORMERLY A.R. 9(G))

Attachment MM-1 (Confidential)

REDACTED

Motion for Protection and Nondisclosure Pending

INDIANA MICHIGAN POWER COMPANY
INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR
DATA REQUEST SET NO. OUCC DR 2
IURC CAUSE NO. 45546

DATA REQUEST NO OUCC 2-12

REQUEST

Messner p. 4, lls. 16-18 states, "Like I&M, AEG's annual costs will also decline due to the termination of its annual lease payment of approximately $74 million." Please identify the expected reduction in I&M's payments to AEG under the Unit Power Agreement reflecting AEG's reduced expenses related to the proposed purchase of Rockport Unit 2 from the Owners Trust and the related termination of AEG's lease with the Owner's Trust. Please provide documentation supporting that expected reduction.

RESPONSE

See "OUCC 2-12 Attachment 1.xlsx" for the requested information.

Description		
Reacquisition Revenue Requirement:		
Purchase Price	$	57,750,000
Accumulated Depreciation (1/2 yr con	$	(4,812,500)
Net Plant	$	52,937,500
WACC		6.02%
Return	$	3,187,561
Gross Revenue Conversion Factor		1.332
Total Pre-Tax Return	$	4,247,250
Property Taxes (est 2.8%)	$	1,482,250
Depreciation (6 yrs - 2028)	$	9,625,000
Estimated Revenue Requirement =	$	15,354,500
Annual Lease Savings:		
Annual Lease Payment	$	73,200,000
Less: Gain Amortization	$	(5,568,000)
Net Lease Expense	$	67,632,000
I&M 70% Lease Savings =	$	(47,342,400)
Net Estimated AEG Bill Impact	$	(31,987,900)

COMPOSITE COST OF CAPITAL
TWELVE MONTHS ENDED December 31, 2019

		Reference	Total Company Average Capitalization $ (1)	% (2)	Cost of Capital % (3)	Composite Cost of Capital (2 x 3) (4)
1.	Long Term Del	Note A	2,633,031,098	51.81%	4.34%	2.25%
2.	Preferred Stocl	Note B	0	0.00%	0.00%	0.00%
3.	Common Stock	Note C	2,448,611,997	48.19%	9.23%	4.45%
4.	Total		5,081,643,095	######		6.70%

AEG

Long Term Debt	217,452,061	59%	1.84%	1.09%
Common Stock	148,225,028	41%	12.16%	4.93%
	365,677,089			6.02%