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INDIANA UTILITY
REGULATORY COMMISSION

I&M Exhibit: _____

Cause No. 45576

INDIANA MICHIGAN POWER COMPANY

PRE-FILED VERIFIED DIRECT TESTIMONY

OF

ANDREW J. WILLIAMSON

Content

DIRECT TESTIMONY OF ANDREW J. WILLIAMSON
ON BEHALF OF
INDIANA MICHIGAN POWER COMPANY

I. Introduction of Witness

Q1. Please state your name and business address.

My name is Andrew J. Williamson and my business address is Indiana Michigan Power Center, P.O. Box 60, Fort Wayne, IN 46801.

Q2. By whom are you employed and in what capacity?

I am employed by Indiana Michigan Power Company (I&M or Company) as Director of Regulatory Services.

Q3. What are your responsibilities as Director of Regulatory Services?

I, along with Company witness Seger-Lawson, am responsible for the supervision and direction of I&M's Regulatory Services Department, which has responsibility for the rate and regulatory matters affecting I&M's Indiana and Michigan jurisdictions. I report directly to I&M's Vice President of Regulatory and Finance.

Q4. Briefly describe your educational background and professional experience.

I received a Degree of Bachelor of Business Administration, Accounting and Finance Majors, in May 2004 from Ohio University. In January 2007, I passed the Certified Public Accountant (CPA) Examination. I am a licensed CPA in the state of Ohio and a member of the American Institute of CPAs.

I was employed by PricewaterhouseCoopers, LLP (PwC) as a Staff and Senior Auditor from August 2004 until December 2007. At PwC, I assisted and led the audits of the books and records of public and private companies, compilation of financial statements and compliance with the standards set forth under the Sarbanes-Oxley Act of 2002.

In January 2008, I joined American Electric Power (AEP) as a Staff Accountant in the Accounting Policy and Research department. Thereafter, I've held positions as a Staff and Senior Accountant in Financial Policy Transaction and Analysis, as a Senior Financial Analyst in Transmission Investment Strategy and as a Manager of Regulatory Accounting Services. In March 2014, I assumed my current position as Director of Regulatory Services for I&M.

Q5. Have you previously testified before any regulatory commissions?

Yes. I have testified before the Indiana Utility Regulatory Commission (IURC or Commission) on behalf of I&M in numerous cases, including I&M's most recent general rate case filings, Cause Nos. 45235 and 44967.

In addition, I have testified before the Michigan Public Service Commission (MPSC) on behalf of I&M, before the Public Utility Commission of Texas on behalf of AEP Texas Central Company (TCC), AEP Texas North Company (TNC), Electric Transmission Texas, LLC (ETT) and Southwestern Electric Power Company (SWEPCO), and before the Corporation Commission of the State of Oklahoma on behalf of Public Service Company of Oklahoma (PSO).

II. Purpose of Testimony

Q6. What is the purpose of your testimony?

The purpose of my testimony is to support:

- I&M's recovery of PJM Capacity Performance Insurance;

- I&M's recovery of its Test Year generating plant without adjustment, through the jurisdictional allocation factors prepared by Company witness Duncan; and
- The appropriate treatment of Rockport Unit 2-related matters as a result of termination of the Rockport Unit 2 Lease in December 2022.

Q7. Are you sponsoring any attachments?

Yes, I am sponsoring:

- Confidential Attachment AJW-1: PJM Capacity Performance Insurance Analysis
- Confidential Attachment AJW-2: PJM Capacity Performance Insurance Policy
- Attachment AJW-3: Rockport Ownership Diagram
- Attachment AJW-4: Notice of Non-Renewal of Rockport Unit 2 Lease

Q8. Are you sponsoring any workpapers?

Yes, I am sponsoring:

- WP-A-OR-3: Adjustment OR-3

Q9. Were the attachments and workpaper that you sponsor prepared or assembled by you or under your direction?

Yes.

Q10. Please summarize your testimony.

The Company's ongoing participation in a group insurance policy to cover PJM Capacity Performance risks is reasonable and necessary. Capacity

Performance insurance allows I&M to reasonably mitigate a large portion of the significant financial risk that a generating unit will underperform or not be available during a Performance Assessment Interval (PAI), which are events determined by PJM and are not within the control of the Company. The group insurance policy, which allows I&M to manage cost, was selected from options solicited through a competitive procurement process. The related expense should continue to be included in cost of service.

There is no basis for the continued disallowance of a portion of I&M's generation resources. The timing considerations that were the foundation for the Commission's disallowance in Cause No. 45235 will become moot before the end of the Test Year, at which time I&M's Lease of Rockport Unit 2 will end and I&M will not have sufficient generating capacity to meet its load obligations. The reacquisition of Rockport Unit 2 to meet I&M's customers' ongoing capacity needs will be the subject of other causes.

Lastly, I&M is requesting approval to use the Resource Adequacy Rider (RAR) to reflect the net reduction in I&M's cost of service associated with the Rockport Unit 2 Lease (Lease) expiration in December 2022. The use of the RAR will allow customers to realize the overall cost reductions in a timely fashion. Additionally, I&M's cost of service in this proceeding includes recovery of the remaining net book value of Rockport Unit 2 at the end of the Lease through 2028 to align with the remaining life of Rockport Unit 1 and plant in service that is common to both units. The remaining net book value of Rockport Unit 2 is predominantly comprised of investments previously approved by the Commission for cost recovery.

III. PJM Capacity Performance Insurance

Q11. Why is I&M addressing PJM Capacity Performance Insurance expense?

In the Commission's Order in Cause No. 45235, it stated:

> *For continued recovery of this premium, I&M is directed to more robustly explain in its next rate case, given I&M' s experience by then and any penalties assessed, the Company's analysis of its risk under PJM's capacity performance rules, including identifying the coverage the Capacity Performance Insurance provides with respect to this risk and any potential coverage gap. I&M should also provide a copy of the policy then in effect and the assessment I&M performed of its penalty risk in determining the coverage secured.*[1]

The cost of PJM Capacity Performance Insurance has been included in the Company's cost of service, and I am addressing each of the elements the Commission requested the Company to address.

Q12. Please explain the PJM Capacity Performance Insurance expense.

The Company, along with the other AEP fixed resource requirement (FRR) companies, share in a group insurance policy that indemnifies the companies up to a certain level against PJM capacity performance charges. The policy is designed to insure against significant underperformance events.

Capacity Performance is a PJM requirement that first applied to the Company's FRR capacity obligations in the 2019/2020 delivery year, which began on June 1, 2019. Under the Capacity Performance requirement, the Company must meet its commitments to generate electricity whenever PJM determines it is needed to meet power system emergencies.

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[1] At pg. 111 of the March 11, 2020 Final Order in Cause No. 45235.

Costly charges can be incurred for generating unit non- or under-performance during specific PAIs that are determined at PJM's sole discretion. For the 2021/2022 Delivery Year, underperformance is subject to an estimated charge of ~$1,200 per megawatt hour (MWh) for an FRR entity that chooses the Physical Settlement Option, which as an example could equate to approximately $1.5 million per hour for each Rockport Unit or approximately $5.250 million per hour for Rockport and the Cook Nuclear Plant.

Q13. Please summarize the analysis of risks that was performed on behalf of the AEP companies to consider Capacity Performance insurance options.

During 2020, AEP conducted an analysis, using a Monte Carlo simulation, which evaluated a range of potential Capacity Performance scenarios and estimated the Capacity Performance charges that could result. This analysis is presented as Attachment AJW-1.

As described above, Capacity Performance charges are determined based on the duration and amount of generation that was committed and is unavailable during a PAI. The analysis estimated the financial risk to be up to approximately $300 million dependent on the number of PAI hours and unit underperformance during that period.

The recommendation was a policy that would reasonably cover the estimated financial risk associated with the worst 20% of outcomes based on an average of 15 annual Capacity Performance hours per year which was estimated to result in a Capacity Performance charge of approximately $140 million.

Q14. Please explain the Capacity Performance insurance policy, its coverage, and any potential coverage gap.

The group insurance policy (Attachment AJW-2) covers I&M and other AEP operating companies participating in FRR with a policy limit of $150 million and a $3 million deductible. Please refer to paragraph 5 of Attachment AJW-2 for exclusions associated with the insurance policy. The insurance policy was selected from options solicited through a competitive procurement process.

Q15. What is I&M's share of the Capacity Performance Insurance expense?

I&M's forecasted Capacity Performance insurance expense for 2022 is $473,193 (Total Company).

Q16. Have any of I&M's generating units been assessed a Capacity Performance charge to date?

Yes. As of June 1, 2021, there has been one PAI since Capacity Performance applied to FRR capacity obligations for which I&M's generating units were assessed a Capacity Performance charge; this took place on October 2, 2019. A charge was incurred due to performance shortfalls on AEP's FRR commitments during a two hour event. In total four AEP generators, including I&M's Cook Nuclear Plant and Rockport experienced shortfalls during three five minute PAI's for which PJM calculated charges.

As an FRR entity, I&M has the ability to elect the Physical Settlement Option, where it would be required to commit additional capacity in the following PJM Delivery Year to compensate for the underperformance. In this instance, the underperformance of I&M's units was not significant and I&M was able to settle physically by providing additional MWs in AEP's FRR Plan for the 2020/2021 Delivery Year.

Q17. Is it reasonable to continue purchasing Capacity Performance insurance?

Yes. It is common for businesses to use insurance products to protect against events that have a low likelihood of occurring, but if they did, they would result in a significant cost. Capacity Performance insurance allows I&M to reasonably mitigate a large portion of the significant financial risk that a generating unit would underperform or not be available during a PAI.

As discussed previously, PAI's are determined by PJM and are not within the control of the Company. Similarly, unit performance and availability is not fully within the control of the Company. It is impossible to completely eliminate the risk that a generating unit may be de-rated or unavailable during a PAI and attempting to do so would come at a significant increase in the level of investment and annual maintenance expense.

Participating in this group insurance policy allows I&M to reasonably manage this significant financial risk while leveraging economies of scale by sharing the cost of a larger insurance policy with other AEP operating companies. Also, participating with a more diverse set of generation resources diversifies the risk of non-performance across the entire generating portfolio because there is opportunity within our FRR plan for over- and under-performance of units to be netted.

IV. Excluded Capacity from Cause No. 45235

Q18. Please explain the Excluded Capacity from Cause No. 45235.

The Commission found that "I&M should bear the ramification of not contractually protecting the Company from termination of the IMMDA load well before the Rockport Unit 2 lease is to expire".[2] It therefore rejected the Company's proposed adjustment to annualize the expiration of the IMMDA contracts and instead imputed the expiring wholesale load into I&M's jurisdictional demand allocation factors as if the wholesale load continued to be

[2] At pg. 83 of the March 11, 2020 Final Order in Cause No. 45235.

served by I&M. This resulted in excluding a percentage of all of I&M's capacity resources allocated on demand from Indiana retail base rates.

Q19. Is the Company proposing any adjustments to its forecasted jurisdictional study, or proposed demand and energy allocation factors, to reflect the subtraction or addition of any wholesale load?

No. The Company is proposing no such adjustment in this case. Company witness Duncan discusses the proposed demand and energy allocation factors for the Test Year, and how they remain within the range of allocation factors approved by the Commission over the last 30 years.

Q20. Is the misalignment the Commission relied upon in Cause No. 45235 still applicable?

No. During the Test Year in this proceeding, the Rockport Unit 2 Lease will end. At that time, I&M will become short the amount of capacity necessary to serve customers through the end of the 2022/2023 PJM Delivery Year. To address that shortfall, I&M entered into an agreement with the Rockport Unit 2 owners that allows I&M to commit Rockport Unit 2 for the remainder of the Delivery Year, at a cost equal to PJM capacity market rates, which ends May 31, 2023.

Absent approval to purchase or own additional capacity resources, beginning June 1, 2023[3] I&M will continue to be short the amount of capacity necessary to serve customers. If the Commission continued to exclude a portion of I&M's remaining capacity resources from base rates it would cause I&M's short capacity position for Indiana retail customers to be even larger. To say this another way, the capacity the Commission excluded in Cause No. 45235 is

[3] PJM's capacity planning years are from June 1 through May 31. To qualify for capacity for a given planning year, generation resources must be available and committed for the full period.

needed during the Test Year and going forward to serve Indiana retail customers.

Q21. Please summarize the major sources of generating capacity that serve I&M's customers.

Figure AJW-1 illustrates certain generating units that serve I&M's customers. These units are either owned or resources for which I&M has long-term agreements for the capacity and energy.

Figure AJW-1. Generating Units

Plant	Size (ICAP MW)	In-Service Year
Hydro facilities	22	1904-1923
Cook Nuclear Plant Unit 1 & Unit 2	2278	1975 and 1978
Rockport Unit 1 (coal)	1320	1984
Rockport Unit 2 (coal)	1300	1989

The current operations, expenses, and investments associated with these units are discussed by Company witnesses Kerns (fossil and hydro) and Lies (nuclear) in their testimonies. Additionally, I&M has purchased power from Ohio Valley Electric Company (OVEC) since 1955, subject to a Federal Energy Regulatory Commission (FERC)-jurisdictional agreement. Those OVEC purchases are considered in I&M's general rate cases, annual Fuel Cost Adjustment and RAR cases. I&M has also received approval from the Commission to own 35 MW of solar generation and purchase 450 MW of power from wind generating facilities.

Q22. Were any of I&M's generating units constructed to meet any particular customer or customer class's needs?

No. I&M plans and operates its capacity resources as a single integrated system for the benefit of all customers. This is evidenced by our Integrated Resource Plans, how capacity is submitted to PJM to meet load obligations and historical cost of service calculations.

Additionally, during the construction of Cook Units 1 and 2 and Rockport Units 1 and 2, I&M was a party to the AEP-East Interconnection Agreement, which created the AEP-East Pool. This agreement was first approved by the Federal Power Commission, the predecessor to FERC. The generating facilities of the Pool members were planned, designed, built (or purchased), and operated on an integrated system basis to meet the needs of all of the AEP-East operating companies. Given the integrated nature of the AEP-East Pool and the dispatch of its resources, the addition of an individual I&M customer, whether retail or wholesale, would not have driven a decision to add generation.

Q23. Please summarize the benefits to I&M's customers from its past participation in the AEP-East Pool.

The integrated approach to the AEP system allowed the member operating companies to maximize economies of scale and allowed customers to receive power from the lowest cost resources in the AEP-East Pool.

By fulfilling its obligations to the AEP Pool, where generating units were economically dispatched on an AEP system-wide basis, I&M's load was served with generation from the most economical generating source available at the time, regardless of operating company ownership or geographic location on the AEP system. This construct provided significant benefits to I&M's retail customers, much in the same way that RTOs benefit customers today.

Q24. How was generation length treated during I&M's membership in the AEP-East Pool, and how is such length treated today?

Capacity equalization revenues and primary energy payments from sales of capacity and energy length in the AEP-East Pool were used to reduce retail customer rates or delay rate increases. This approach preserved I&M's integrated generation capacity for the benefit of Indiana retail electric service as the retail load changed from year to year.

Ultimately, as technology and regulatory policy evolved, I&M and other AEP East affiliates joined the PJM RTO. In addition, the AEP-East Pool has been replaced with the Power Coordination Agreement (PCA) which continues to provide customers benefits by combining I&M's generation resources with those of other AEP operating companies in PJM to fulfill AEP's and I&M's PJM capacity obligation. Today, generation "length" beyond that directly needed by I&M's current customer mix may be compensated through the PCA or sold into the PJM market and associated revenue is used to reduce I&M's retail revenue requirement. In addition, retail customers benefited significantly over many years from the allocation of generation costs to wholesale customers who have a choice whether to purchase generation from I&M. In this way, I&M's generation has long been devoted to reducing the ongoing cost of retail service. Accordingly, the facilities have long been reasonably necessary to provide the efficient and reliable provision of retail electric utility service.

Q25. As a general matter, is capacity length beyond that which is needed to match the Test Year forecasted load requirements used and useful?

Yes. Electric load is not constant nor within I&M's control. It varies over time by customer type and economic conditions. As a result, generating capacity will rarely, if ever, exactly match shifts in load requirements. A period where available capacity exceeds customer load does not mean that the Company has unreasonable “excess” capacity above and beyond what is needed to provide service the customers.

Public utilities in Indiana, such as I&M, are required to make investment decisions which ensure that it can provide adequate and dependable utility service available now and in the future. Utility plant generation facilities require considerable lead time both for planning and construction purposes. During the course of the utility planning and construction, many of the factors the utility relied on in its decision to construct a unit can change, such as economic conditions, forecasted load, environmental regulations and technology. Consequently, even new generation facilities may not match the load requirements. This is further reinforced by the requirement to maintain a minimum reserve margin to address the variable and unpredictable nature of load requirements and available generation.

The decision to construct a unit however, is based on what was known or should have been reasonably known at the time the decision to move forward was made. Any later assessment of that decision should be based on the same approach. One cannot reasonably assess previous decisions to add generating capacity based on current conditions, doing so would implicate hindsight.

Furthermore, and generally speaking, historically the building of larger generating facilities is, in the long run, more economical than the building of smaller units. This naturally resulted in lumpy generation additions as compared to the load changes they were intended to serve.

Dispatchable capacity serves as an important source of reliability, not only with respect to meeting peak demand, the potential for unplanned outages of other units, and other unforeseen circumstances, but also with respect to the Company’s transition to more renewable, intermittent sources of power.

Recently, the Commission has emphasized that resource planning should preserve flexibility, not constrain it, and also recognized that existing generating capacity can provide a potential bridge to the future.[4]

Q26. What is I&M's projected capacity position as compared to its projected load in 2022?

Upon termination of the Rockport Unit 2 Lease in December 2022, absent the procurement of additional resources, I&M has estimated it will be approximately 300-400 MW short of meeting its PJM capacity obligations on a stand-alone basis for its retail and wholesale customers with existing owned or controlled (such as through a PPA) capacity.

Since I&M plans and operates its generating resources as a single integrated system, the Indiana jurisdictional share of this capacity shortfall is represented by the proposed Indiana demand allocation factor supported by Company witness Duncan. Accordingly, each of I&M's existing capacity resources are needed to serve retail customers through the Test Year and going forward.

[4] *Southern Indiana Gas and Electric Company,* Cause No. 45052 (IURC 4/24/2019), p. 20 ("Outcomes that reasonably minimize such potential risk and serve to foster utility and customer flexibility in an environment of rapid technological innovation on both the utility and customer side of the meter are, therefore, a lens through which we will review Vectren South's request."); p. 22 ("Through the lens of minimizing risk and providing future flexibility the refurbishment option would seem to provide a potential bridge to the future, providing system capacity value that was not sufficiently evaluated."); *Northern Indiana Public Service Company*, Cause No. 45462 (IURC 5/5/2021), p. 68 (also p. 64 n.70 ("As the Commission has noted previously, "[a] key consideration in long-term resource planning is the need to retain maximum flexibility in utility resource decisions to minimize risks. The credibility of the analysis is critical to the effort of Indiana utilities to maintain as many options as possible, which includes off-ramps to react quickly to changing circumstances and make appropriate changes in the resources." (quoting above referenced order in Cause No. 45052 at 24).

Q27. Is I&M's fleet of generation resources used and useful in the provision of electric service to retail customers?

Yes. In assessing used and usefulness of existing capacity, the Commission should reasonably consider the broad public interest in reasonably low rates for utility service and in the availability of adequate and dependable service for the future.

As shown above, the Company's baseload generating facilities were built as part of a construct that provided retail customers long-term, low cost, and reliable generation. The Company's generating capacity has and continues to be devoted to providing utility service. What is not used directly to meet capacity and energy demand is used indirectly to serve retail customers because it reduces operating costs and retail rates through capacity and energy sales[5], and supports reliability.

V. Treatment of Rockport Unit 2

Q28. Please discuss the status of Rockport Unit 2.

I&M and AEP Generating Company (AEG) have received the capacity and energy associated with Rockport Unit 2 (Unit 2) under an agreement approved by the Commission (Lease) since Unit 2 began operation in 1989. In addition, I&M purchases power from AEG's share of Unit 2 through a FERC-approved, cost-based Unit Power Agreement. Attachment AJW-3 provides a summary of the current and historical ownership and lease arrangement associated with the Rockport Plant.

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[5] I&M has proposed 100% sharing of Indiana retail capacity sales revenues and off-system sales margins.

On November 5, 2020, I&M provided an irrevocable notice (Attachment AJW-4) that I&M would not be extending the Lease. As a result, the Lease will expire on December 7, 2022, which is during the last month of the Test Year.

Separately, on May 10, 2021 in Cause No. 45546, I&M filed a petition asking the IURC to allow 50 percent of Rockport Unit 2 to return to I&M ownership at the end of the Lease.

Q29. Please describe the Unit 2 costs included in I&M's proposed base rates.

I&M's proposed base rates include the Unit 2 costs and capital investments that are forecasted during the term of the Lease and the 2022 Test Year. Consistent with past forecasted rate case filings, this includes the forecasted capital expenditures, fuel expense, consumables expense, AEG purchase power expense, off-system sales (OSS), lease expense, other O&M expense, and depreciation expense I&M forecasted to incur during 2022. I&M's Test Year and proposed base rates do not include the cost of purchasing Unit 2.

Q30. Please summarize how Unit 2 capital investments are reflected in I&M's proposed rate base.

I&M's proposed base rates reflect the continued recovery of all Unit 2 capital expenditures made by I&M during the Lease. Specifically, upon expiration of the Lease, I&M's cost of service follows the FERC Uniform System of Accounts (FERC USofA)[6] guidance for accounting for retirements.

This results in a credit to plant in service (FERC Account 101) and a debit to accumulated depreciation (FERC Account 108) for the original cost gross plant balance of all Unit 2 capital investments upon the date the Lease ends, or December 7, 2022. Additionally, I&M included in accumulated depreciation the

[6] FERC Electric Plant Instructions 10

forecasted Unit 2 environmental compliance capital costs incurred as of the expiration of the Lease.

The remaining net book value (NBV) associated with Unit 2 investments made by I&M during the term of the Lease will, upon expiration of the Lease, be in net plant in-service and therefore rate base at the end of the Test Year. This treatment recognizes the Unit 2 capital investments made in accordance with the terms of the Lease were reasonable and necessary in the provision of service to Indiana retail customers and should be fully recovered through I&M's cost of service.

Q31. Please describe the remaining NBV associated with Unit 2.

The remaining NBV is primarily related to environmental control equipment approved in Cause No. 44331 Rockport Dry Sorbent Injection (DSI) and Cause No. 44871 Rockport Unit 2 Selective Catalytic Reduction (SCR). These investments were found by the Commission to be reasonable even if Rockport Unit 2 is only available to I&M's customers through the end of the Lease. Forecasted plant additions during the Capital Forecast Period and other environmental compliance costs are further discussed and supported by Company witness Kerns.

Q32. How is the Unit 2 remaining NBV reflected in I&M's proposed depreciation expense?

I&M is proposing the remaining NBV of Unit 2 be recovered over the remaining life of the Rockport plant as a whole (i.e., Rockport Unit 1 and plant common to both units), which is estimated to reach end of life in 2028 for depreciation rate purposes. This treatment recognizes the Unit 2 investments were reasonable and necessary in the provision to service to customers and allows I&M to mitigate the impact on customers by extending the recovery beyond the period currently used for Rockport Unit 2 depreciation rates.

This is also consistent with the Commission's approved treatment of remaining cost associated with the Tanners Creek Plant, which was retired in 2015, and the remaining NBV was incorporated into Rockport Unit 1 and depreciated over its remaining life.[7]

Q33. Will variances between I&M's actual and forecasted Unit 2 capital expenditures and accumulated depreciation at the end of the Lease be addressed within I&M's ratemaking proposals?

Yes. As described by Company witnesses Seger-Lawson and Duncan, I&M is proposing a Phase-In Rate Adjustment (PRA) process consistent with past forecasted rate cases. The Company proposes that the PRA be used to adjust I&M's final base rates to reflect the lower of actual net plant in-service at the end of the Test Year or the level approved by the Commission in its Final Order in this proceeding.

Q34. How is the Lease expense reflected in I&M's proposed base rates?

The 2022 Test Year revenue requirement reflects the forecasted Lease expense for the period January 1, 2022 through December 7, 2022. I&M's share of the Test Year level of Lease expense, less amortization of the gain on sale, is $69,204,240 (Total Company) and is reflected in FERC Account 507. The AEG share of the Test Year level of Lease expense is reflected in the AEG UPA bill which is currently, and proposed to continue to be, tracked in the RAR to allow rates to be adjusted as needed to match the forecasted cost with the actual cost.

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[7] Cause No. 44555.

Q35. Please summarize how I&M is proposing to address the cost of service changes that will occur upon the termination of the Lease.

As I discuss in more detail below, I&M proposes to use the RAR to reflect the net cost reduction that will occur when the Lease payment obligation is terminated. I&M's proposed use of the RAR will ensure that post-Test Year rates are adjusted on a timely basis so that customers timely receive the net benefits associated with the Lease ending.

Other changes in operating costs such as fuel expense, consumables expense, purchase power expense and off-systems sales will naturally be captured by other existing rider mechanisms, namely the fuel cost adjustment (FAC), Environmental Cost Rider (ECR), RAR and Off-System Sales (OSS)/PJM Rider.

Figure AJW-2 generally describes the various categories of costs associated with Unit 2 and the Test Year and post-Test Year ratemaking proposals.

Figure AJW-2. Rate treatment of Unit 2 expenses

Cost category	During test year	After test year
Capital expenditures	Base rates	Base rates
Fuel expense	Base rates/FAC	Base rates/FAC
Consumables expense	Base rates/ECR	Base rates/ECR
AEG purchased power exp.	Base rates/RAR	Base rates/RAR
Off-system sales	OSS/PJM rider	OSS/PJM rider
Lease expense	Base rates	Base rates/RAR
Other O&M expense	Base rates	Base rates/RAR*
Property tax expense	Base rates	Base rates/RAR*
Depreciation	Base rates	Base rates

* In the event that these expenses are required to be excluded from I&M's retail cost of service after the expiration of the Lease, I&M proposes to file a revised RAR revenue requirement that will reflect the necessary expense reductions.

Q36. How will the elimination of the Lease payment be reflected in I&M's ongoing rates?

Once the Lease ends, I&M proposes to include the ongoing savings resulting from the elimination of the Lease payment as a reduction to cost of service in I&M's RAR. Subsequent to the Commission's Final Order in this proceeding and prior to January 2023, I&M plans to file a revised RAR revenue requirement that will reflect in ongoing rates the reduced operating expenses resulting from the elimination of the Test Year level of Lease expense.

Beginning in January 2023 this will result in a reduction to the RAR annual revenue requirement of $69,204,240 (Total Company). This annual reduction will continue to be reflected in the RAR until I&M's next base rate case. In addition, upon expiration of the Lease and going forward, the AEG purchased power cost tracked in the RAR will reflect the AEG share of the Lease expense being eliminated.

This proposal ensures that upon expiration of the Lease and going forward, customer rates timely reflect in I&M's operating expenses the reduction associated with the termination of the Lease.

Q37. Please estimate the total annual Lease expense savings that will be reflected in the RAR going forward.

Figure AJW-3 summarizes the annual lease expense savings.

Figure AJW-3. Rockport Unit 2 Lease Expense Summary (in Millions)

	I&M	AEG
Annual Lease Expense[1]	$ 69.2	$ 67.3
I&M Share	100%	70%
	$ 69.2	$ 47.1
Indiana Jurisdictional Share[2]	71%	71%
	$ 48.9	$ 33.3
Total Indiana Expense	$ 82.2	

1 - Net of gain on sale amortization
2 - Proposed demand allocation factor per Company witness Duncan

Going forward, I&M's RAR will reflect approximately $82 million of annual Lease savings as a result of a reduction in the AEG Rockport Unit 2 bill and the annual credit proposed by I&M.

Q38. Please explain Adjustment OR-3.

Since the future ownership of Unit 2 is currently unknown, Adjustment OR-3 removes from the Test Year forecast the one month of operating fee revenue that would only be realized if I&M were operating the unit on behalf of the Lease Owners.

Q39. Are costs associated with I&M's proposed Unit 2 purchase price included in I&M's forecast and proposed rates in this case?

No. The costs associated with potential ownership will be addressed in a later IURC filing.

Q40. Are I&M's proposals and cost of service associated with Unit 2 as discussed above reasonable?

Yes. Regardless of whether I&M ultimately owns Unit 2, the Lease expense will be eliminated, so it is appropriate to approve the requested use of the RAR to reduce customer rates. Additionally, the termination of the Lease at the end of 2022 makes it appropriate for I&M to plan for the retirement and depreciation of the remaining NBV of Unit 2. It is reasonable and necessary to earn a return on and of the remaining NBV of Unit 2 at the end of the Lease because the investments comprising that remaining NBV were made in accordance with the Lease, are necessary to comply with environmental regulations, and are used and useful in the provision of electric service to customers.

Additionally, if I&M reacquires Unit 2, adjustments to depreciation rates can be made in the later IURC filing addressing the associated cost recovery and retail ratemaking. Specifically, I&M would propose to recalculate Rockport depreciation rates reflecting the ongoing operation, rather than the retirement, of Unit 2 at the end of the Lease. If I&M does not reacquire Unit 2, no change is needed.

Q41. Does this conclude your pre-filed verified direct testimony?

Yes.

VERIFICATION

I, Andrew J. Williamson, Director of Regulatory at Indiana Michigan Power Company, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information, and belief.

Date: 6/28/2021 Andrew J. Williamson

Andrew J. Williamson

Indiana Michigan Power Company

Attachment AJW-1

Witness: A.J. Williamson

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

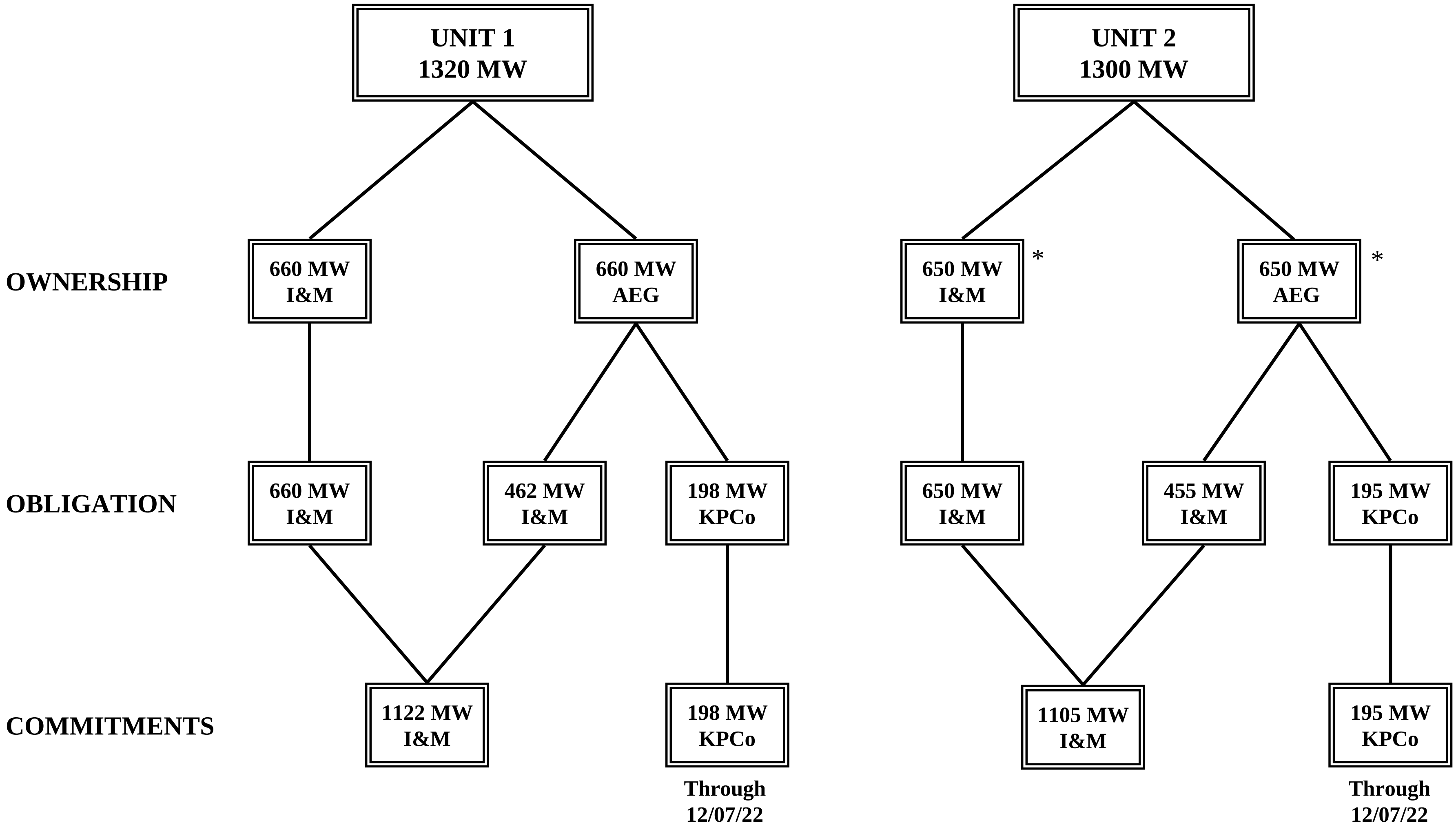
Indiana Michigan Power Company

Attachment AJW-2

Witness: A.J. Williamson

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

ROCKPORT PLANT
OWNERSHIP, OBLIGATION AND COMMITMENTS



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

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

Toby L. Thomas
President & Chief Operating Officer

November 5, 2020

By Federal Express

Wilmington Trust Company,
as Lessor
Rodney Square North
Wilmington, DE 19890
Attn: Corporate Trust Administration

[redacted]

[redacted]

[redacted]

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Re: Notice of Non-Renewal of Rockport Unit 2 Lease

Dear Owner Trustee and Owner Participants:

Pursuant to Section 13(a)(i) of the December 1, 1989 Lease Agreements ("Lease") by which Indiana Michigan Power Company ("I&M") and AEP Generating Company ("AEG") lease an Undivided Interest in Rockport Generating Station Unit 2, notice is hereby given to Wilmington Trust Company, as Lessor, that I&M and AEG elect "to return the Undivided Interest to the Lessor pursuant to Section 5" of the Lease upon expiration of the Basic Lease Term.

Please acknowledge receipt of this notice below and return it to Toby L. Thomas at P.O. Box 60, Fort Wayne, IN 46801, or at tthomas@aep.com.

Sincerely,

Toby L. Thomas

Toby L. Thomas
President and Chief Operating Officer
Indiana Michigan Power Company

Julie A. Sherwood

Julie A. Sherwood
Vice President
AEP Generating Company

Acknowledged:

Wilmington Trust Company, as Lessor

By: ______________________________

Name: ______________________________

Title: ______________________________