STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF INDIANA MICHIGAN POWER COMPANY (I&M) FOR APPROVAL OF (1) ISSUANCE TO I&M OF CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY UNDER IND. CODE § 8-1-8.5-2 FOR THE ACQUISITION AND DEVELOPMENT THROUGH PURCHASE SALE AGREEMENTS (PSA) OF TWO SOLAR POWER GENERATING FACILITIES TO BE KNOWN AS LAKE TROUT, AND MAYAPPLE (CLEAN ENERGY PSA PROJECTS); (2) TO THE EXTENT NECESSARY, ISSUANCE OF AN ORDER PURSUANT TO IND. CODE § 8-1-2.5-5 DECLINING TO EXERCISE JURISDICTION UNDER. IND. CODE § 8-1-8.5-5(e) (3) APPROVAL OF EACH PSA PROJECT AS A CLEAN ENERGY PROJECT UNDER IND. CODE § 8-1-8.8-11; (4) APPROVAL OF TWO SOLAR RENEWABLE ENERGY PURCHASE AGREEMENTS FOR PROJECTS TO BE KNOWN AS ELKHART COUNTY AND SCULPIN (CLEAN ENERGY PPA PROJECTS) AS CLEAN ENERGY PROJECTS UNDER IND. CODE § 8-1-8.8-11; (5) ASSOCIATED TIMELY COST RECOVERY UNDER IND. CODE § 8-1-8.8-11 FOR ALL PSA AND PPA PROJECTS; AND (6) OTHER ACCOUNTING AND RATEMAKING AUTHORITY.	)	**CAUSE NO. 45868**

<u>SUBMISSION OF CORRECTIONS TO DIRECT AND REBUTTAL TESTIMONY</u>

Petitioner, Indiana Michigan Power Company ("I&M", "Petitioner", or "Company"), by counsel, respectfully submits its corrections to the following direct and rebuttal testimony:

- I&M Witness Gaul's confidential direct testimony, page 43. A typographical error was discovered and has been corrected. The corrected confidential version of testimony will be filed through the confidential tab of the

Commission's portal and provided to parties who have executed a non-disclosure agreement with the Company.

- I&M Witness Taberner's direct testimony of, page 2, and rebuttal testimony, page 9. Typographical errors were discovered and have been corrected.
- I&M Witness Williamson's rebuttal testimony, page 13. Correction to Q/A30 was necessitated by the corrected testimony of Wes R. Blakley prefiled by the Indiana Office of the Utility Consumer Counselor on June 5, 2023.

Clean revised copies will also be included in the court reporter copies offered into evidence at the hearing.

Respectfully submitted,

Lauren Aguilar

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CERTIFICATE OF SERVICE

The undersigned hereby certifies that a copy of the foregoing was served this 15th day of June, 2023, by email transmission, hand delivery or United States Mail, first class, postage prepaid to:

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Figure TBG-4

TOTAL INSTALLED CAPITAL COST	
	Mayapple 224 MW Solar
PSA Price	
[redacted]	[redacted]
Owner's Costs	
Resiliency & Integration	[redacted]
Project Management	
Other Owner's Costs	
Acquisition and Development	[redacted]
Overheads	
AFUDC	
Project Contingency	[redacted]
Total Facility Cost	[redacted]

Q62. What are the component costs included in the Best Estimate?

The Best Estimate of the total installed capital costs includes: the PSA Price, Owner's costs, and a Project Contingency. I summarize each of these components below.

The PSA Price reflects the cost of the negotiated purchase price between the Company and the Developer for the engineering, procurement and construction of the Clean Energy PSA Projects, including base interconnection costs [redacted]

Owner's Costs can be broken into two general categories: those associated with construction oversight, engineering/design reviews, and the physical integration of the project into I&M operations, and; those incurred by the Company for the for the Potomac -Appalachian ~~Alleghany~~ Transmission Highline (PATH) project. I returned to Transmission Planning in 2011 as Manager of Compliance, Modeling and Process Development. I moved to my current position as I&M Transmission Planning Manager in 2016. I am a licensed professional engineer in the state of Ohio.

Q4. What are your responsibilities as a Transmission Planning Manager?

My responsibilities include transmission planning activities in Indiana and Michigan for I&M and AEP Indiana Michigan Transmission Company (IMTCO). I&M and IMTCO are in the AEP Zone of PJM LLC (PJM) Regional Transmission Organization (RTO)[1]. For ease of reference, these subsidiaries will collectively be referred to as I&M in this testimony.

II. Purpose of Testimony

Q5. What is the purpose of your testimony?

The purpose of my testimony is to support the Company's request for approval of four solar projects consisting of two purchase sale agreement (PSA) projects and two purchase power agreements (PPA) (collectively the Clean Energy Projects), by explaining the Clean Energy Projects' transmission interconnection to the PJM RTO. In addition, I will address the costs of these interconnections. I am also presenting, with input from Company witnesses David Lucas, Mark Becker and Timothy Gaul, the Company's response to the Indiana Utility Regulatory Commission's (IURC or Commission's) General Administrative Order (GAO) 2022-01, which became effective August 1, 2022.

[1] IMTCO also has an investment in a switchyard in Greentown IN that is in the Midcontinent Independent System Operator RTO.

affected by the size of the proposed generating facilities. The Mayapple and Lake Trout Projects are not only connecting at a higher voltage but also have greater generating capacity than the Elkhart County and Sculpin Projects. Both factors lead to higher interconnection costs for the two PSA Projects over the two PPA Projects.

IV. Project Costs

Q9. OUCC witness Krieger (p~~p~~. ~~13-14~~12) asserts that interconnection costs are very difficult to estimate. Does the Company have previous experience with Independent Power Producer interconnection projects?

Yes. AEPSC has completed 56 interconnection projects since 2006. This includes 16 interconnection projects at the 138kV voltage and 17 interconnection projects at 345kV voltage. AEP has considerable experience in analyzing and facilitating interconnections to its system.

Q10. Please describe the current process used to estimate the PJM interconnection costs.

All projects are built in accordance with good engineering practices and the planning/operating standards and guidelines set forth by North American Electric Reliability Corporation (NERC), PJM, the Institute of Electrical and Electronics Engineers, Inc., the National Electrical Safety Code (NESC), the Occupational Safety and Health Administration (OSHA), and the American National Standards Institute (ANSI). A robust modeling process is used to prepare project estimates. Inputs to the modeling process include: historical results by project type; current labor and unit price cost contracts that are competitively bid; blanket contract costs for materials for the entire AEPSC system that take advantage of volume pricing; construction standards to reduce

Q30. ~~**On page 4 of his testimony, OUCC witness Blakley expresses concerns over use of the term "deferred average monthly rate base." Did you use that specific term in your testimony?**~~

~~No. This is not a term used in my testimony. Mr. Blakley appears to be combining together multiple topics addressed in my testimony to create this specific term. However, I want to be clear to the Commission since his testimony places these terms in quotes that his reference is not correct.~~

Q31. Please summarize OUCC witness Blakley's testimony regarding Asset Retirement Obligations (AROs).

Mr. Blakley generally addresses what an ARO is on page 3, lines 15-22 and page 4, lines 1-2. In addition, on pages 5-8 Mr. Blakley has several Q&As discussing this topic. He concludes (inaccurately as I explain below) that ARO costs are or should be included in I&M's proposed depreciation rates. Ultimately, on page 9 of his testimony (lines 7-20), Mr. Blakley recommends that I&M should not include any forecasted or estimated non-cash expensed ARO balances that reside on I&Ms balance sheet in its SPR tracker. He testifies that they are not included in base rates as a return on investment nor a recovery of expenses and therefore should not be included in the SPR. Mr. Blakley states that that I&M should update its depreciation rates including estimates for ARO decommissioning costs net of salvage in later depreciation studies following in-service dates of the new solar resources. He adds that the proper ratemaking treatment for ARO decommissioning cost estimates is that they be included in I&M depreciation rates and net salvage calculations along with all the other existing asset decommissioning costs, and at the time of retirement of the assets, the actual removal costs incurred be charged to accumulated depreciation.

Q32. Do you agree with Mr. Blakley's recommendation related to AROs?

I agree that I&M should not recover a return on the ARO non-cash asset *balances* and clarify that I&M has not requested to do so. I disagree with Mr.

I&M Exhibit: _____

INDIANA MICHIGAN POWER COMPANY

PRE-FILED VERIFIED DIRECT TESTIMONY

OF

TIMOTHY B. GAUL

Content

DIRECT TESTIMONY OF TIMOTHY B. GAUL
ON BEHALF OF
INDIANA MICHIGAN POWER COMPANY

I. Introduction of Witness

Q1. Please state your name and business address.

My name is Timothy B. Gaul and my business address is 1 Riverside Plaza, Columbus, OH 43215.

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

I am employed by American Electric Power Service Corporation (AEPSC), a wholly-owned subsidiary of American Electric Power Company, Inc. (AEP), as Director – Regulated Infrastructure Development. AEP is the parent company of Indiana Michigan Power Company (I&M or Company). AEPSC provides engineering, financing, accounting, regulatory, and similar planning and advisory services to AEP's regulated electric operating companies, including I&M.

Q3. Briefly describe your educational background and professional experience.

I have a Bachelor of Science degree from the State University of New York College of Environmental Science and Forestry at Syracuse University, in New York and a Master of Science degree from Creighton University, in Omaha, Nebraska. I also have a graduate certification in Financing and Deploying Clean Energy from Yale University.

During my career with AEP, I served as Director of the Transmission Siting Department where I led the team responsible for providing transmission project siting and development support for projects across AEP's 13 state transmission footprint and for competitive transmission siting efforts. I assumed my current position as a Director in the Regulated Infrastructure Development group in 2021.

Prior to joining AEP in 2016, I was the Vice President of the US Power and Energy Division at Louis Berger, an international architecture, planning, and engineering firm, where I was responsible for the company's US energy program serving utility clients, energy developers, and the federal government.

Q4. What are your responsibilities as Director of Regulated Infrastructure Development?

As Director, Regulated Infrastructure Development, I am part of a team that: (1) structures and issues requests for proposals (RFPs) for energy resources; (2) reviews and evaluates proposals received in response; (3) negotiates and finalizes the agreements with the successful respondent(s); (4) serves as the primary interface between the Company and the Independent Monitor; and (5) provides ongoing commercial support as the Company pursues regulatory approvals and moves forward to construction and eventual completion of energy projects.

Q5. Have you previously testified before any regulatory commissions?

Yes. I have provided testimony before state utility commissions in Michigan, Oklahoma, Kansas, Missouri, Illinois, Pennsylvania, West Virginia, Virginia, and New Jersey.

Q6. What is the purpose of your testimony?

I support I&M's request for approval of a) the acquisition through two Purchase and Sale Agreements (PSAs) of the Lake Trout and Mayapple solar power generating facilities (Clean Energy PSA Projects); and b) two solar Renewable Energy Purchase Agreements for the Elkhart County and Sculpin Projects (Clean Energy PPA Projects), all of which were selected through a competitive all-source RFP. For ease of reference each Renewable Energy Purchase Agreement is referred to in this filing as a power purchase agreement or "PPA".

More specifically, my testimony includes the following:

- Overview of the 2022 All Source RFP (2022 RFP) and selected projects;
- Review of the RFP development and issuance process and engagement of Independent Monitor;
- Description of the proposal review and selection;
- Overview of the negotiation process, market pressures;
- Overview of the PSAs;
- Overview of the PPAs;
- Best Estimates of the PSA Project Costs; and
- Summary and Conclusion

Q7. Are you sponsoring any attachments?

Yes, I am sponsoring:

Attachment TBG-1 – 2022 All Source RFP

Attachment TBG-2C – Confidential/Highly Competitively Sensitive Versions of the Bid Score Summary Sheet

Attachment TBG-3 and 3C – Lake Trout PSA (Confidential/Highly Competitively Sensitive)

Attachment TBG-4 and 4C – Mayapple PSA (Confidential/Highly Competitively Sensitive)

Attachment TBG-5 and 5C – Sculpin PPA (Confidential/Highly Competitively Sensitive)

Attachment TBG-6 and 6C – Elkhart County PPA (Confidential/Highly Competitively Sensitive)

In addition, I am co-sponsoring a portion of Attachment BT-1 and BT-2 (included with Company witness Taberner testimony), which provides the information required under the Commission's General Administrative Order 2022-01.

Specifically, I support the description of the new generation's expected capacity factors, dispatchability, and accreditation characteristics.

Q8. Are you sponsoring any workpapers?

Yes, I am sponsoring:

WP-TBG-1C – Risk Register for Lake Trout PSA Project (Confidential/Highly Competitively Sensitive)

WP-TBG-2C – Risk Register for Mayapple PSA Project (Confidential/Highly Competitively Sensitive)

Q9. Were these attachments and workpapers prepared or assembled by you or under your direction and supervision?

Yes.

II. Overview of the 2022 All Source RFP and Selected Projects

Q10. Please provide an overview of the RFP.

The I&M 2022 All Source RFP sought to acquire approximately 500 MW of solar, 800 MW of wind, and other supplemental capacity resources through either PPAs or PSAs to meet the overall capacity and energy needs of the Company identified in the Preferred Portfolio. The Integrated Resource Plan (IRP) is discussed by Company witnesses Lucas and Becker. The competitive RFP targeted projects with commercial operation dates to support the Company's capacity needs during PJM Interconnection LLC's (PJM) 2025-2026 and 2026-2027 Planning Years. The 2022 All Source RFP is summarized in Table TBG-1 below. The 2022 All Source RFP is available in Attachment TBG-1.

The RFP was designed in a way that allowed for an open, non-discriminatory competitive procurement process that considered both third-party and utility ownership, a range of resource types or combinations of resource types, and various sizes and capacities within reasonable operational limits for utility needs. The RFP required projects to be located within either Indiana or Michigan for solar or supplemental capacity resources. An expanded geographic scope was used for wind project consideration to engage a broader range of potential projects that included Illinois and Ohio. Additionally, all projects were required to either be pursuing a PJM interconnection service agreement or have firm transmission from MISO into PJM to be considered eligible for consideration.

Table TBG-1: I&M 2022 All-Source Request for Proposal Summary

Category	Wind (Storage Optional)	Solar (Storage Optional)	Supplemental Capacity Resources[1]
Nameplate Capacity	Approximately 800 MWac	Approximately 500 MWac	Supplemental capacity to meet overall capacity need.
Location	Indiana, Michigan, Ohio or Illinois	Indiana or Michigan	Indiana or Michigan
Battery Energy Storage Option	Targeting within a ratio of 5:1 to 3:1 of nameplate and greater than or equal to 4 hours of storage	Targeting within a ratio of 5:1 to 3:1 of nameplate and greater than or equal to 4 hours of storage	Greater than or equal to 4 hours of storage, with consideration for projects that can enhance existing I&M facilities
Carbon Emissions Requirement	N/A	N/A	Generating units must have low carbon emissions or mitigating technology
Minimum PPA/PSA Size	5 MWac	5 MWac	5 MWac
Minimum PSA Design Life	30 year	30 year	Preferred 30 year; minimum 15 year (technology dependent)
Minimum PPA Term	15 year (must show a 30 year option)	15 year (must show a 30 year option)	15 year
PPA Price Structure	Fixed price / Non-Escalating All-in around-the-clock price	Fixed price / Non-Escalating All-in around-the-clock price	N/A
Affiliate or Self Build	No	No	No

[1] Standalone Storage, Emerging Technologies, Thermal, and Other Capacity Resources

Q11. Please provide a summary of the Projects selected in the I&M 2022 RFP.

Following the RFP process, I&M entered into two PSAs for 469 MW of solar resources (Clean Energy PSA Projects) and two PPAs for 280 MW of solar resources (Clean Energy PPA Projects) as shown in Table TBG-2 below (collectively referred to as Clean Energy Projects). All of the projects are connected to the PJM grid, and all are located in Indiana within I&M's service territory except for the Mayapple Project, which will directly connect with an AEP transmission line that extends west of the I&M service territory in Pulaski County. I&M has also entered into a capacity only purchase agreement (CPA) for 210 MW of natural gas peaking capacity. The CPA agreement is not part of this request for approval and will be addressed in a separate filing.

Table TBG-2. Summary of Selected Projects

Developer	Project	Type	Form	COD (m/yr)	Size (MW)[1]
EDF	Lake Trout	Solar	PSA	4/2026	245
Lightsource bp	Mayapple	Solar	PSA	5/2026	224
					469
EDF	Sculpin	Solar	30 yr PPA	12/2025	180
Savion	Elkhart County	Solar	30 yr PPA	12/2025	100
Rockland	Montpelier	NG Peaking	7 yr Capacity-only	Existing	210
					490
TOTAL					**959 MW**

Q12. Please further describe each of the Clean Energy Projects that are subject in this proceeding.

I&M is proposing the following two Clean Energy PSA Projects, with the Company purchasing 100% ownership of the project and operating the facilities for the life of the facility.

- The Lake Trout Project is located in Indiana and will produce 245 MWs of solar generation using single axis tracking design. The developer for this project is EDF Renewables Development, Inc. (EDF). The Project is expected to be operational in April of 2026. The Lake Trout Project is expected to be capable of producing enough energy to power approximately 73,500 homes.
- The Mayapple Project is located in Indiana and will produce 224 MWs of solar generation using single axis tracking design. The developer for this project is Lightsource bp. The Project is expected to be operational in

[1] All MW references refer to installed capacity, or ICAP.

May of 2026. The Mayapple Project is expected to be capable of producing enough energy to power approximately 67,200 homes.

I&M proposes the following two Clean Energy PPA Projects, with the Company contracting for the capacity, energy, and renewable energy certificates (RECs) from these facilities, once the resources are operational.

- The Sculpin Project is located in Indiana and will produce 180 MWs of solar generation using single axis tracking design. The developer for this project is EDF. The Project is expected to be operational by December 15, 2025. The Sculpin Project is expected to be capable of producing enough energy to power approximately 54,000 homes.
- The Elkhart County Project is located in Indiana and will produce 100 MWs of solar generation. The developer for this Project is Savion, LLC (Savion). This Project is expected to be operational by December 31, 2025. The Elkhart County Project is expected to be capable of producing enough energy to power approximately 30,000 homes.

Q13. Please provide an overview of the Project Developers and their experience developing renewable energy projects.

Renewable energy agreements were negotiated and executed with three Project Developers: *EDF, Lightsource bp*, and *Savion.* All three companies are well established developers of renewable energy projects and have specific experience developing projects in the region. Each developer has provided the below company summary information:

<u>EDF</u>

EDF is a market leading independent power producer and service provider with 35 years of expertise in renewable energy. The company delivers grid-scale power resources through wind (onshore and offshore), solar photovoltaic, and storage projects; distribution-scale power through solar and storage projects; and asset optimization through providing technical, operational, and commercial expertise to maximize performance of generating projects. EDF Renewables' North American portfolio consists of 24 GW of developed projects and 13 GW under service contracts. EDF Renewables North America is a subsidiary of EDF Renewables, the dedicated renewable energy affiliate of the EDF Group based in France.

<u>Lightsource bp</u>

Lightsource bp is a global leader in the development and management of solar energy and energy storage projects and a 50:50 joint venture with bp. For more than a decade, Lightsource bp has delivered affordable, safe and sustainable energy to businesses and communities around the world. Their team includes nearly 1,000 industry experts, working in 19 countries, providing full scope development for projects, from initial site selection, financing and permitting to long-term management of solar projects and energy sales to their customers. Lightsource bp in the U.S. is headquartered in San Francisco, CA.

<u>Savion</u>

Savion, a Shell Group portfolio company operating on a stand-alone basis, is an industry-leading solar and energy storage organization with a growing portfolio of more than 23 GW. Savion is currently one of the country's largest utility-scale solar and energy storage project development companies. Combined, the Savion team has developed 2,533 MW of operating, in-construction, and contracted solar energy projects, with a current solar and storage development pipeline of 15,829 MW and 7,886 MW, respectively. Savion has contracted 891 MW with utility and C&I clients in PJM and has a current PJM solar and storage development pipeline of 4,099 MW and 1,428 MW, respectively.

III. Competitive RFP Development / Issuance and Engagement of Independent Monitor

Q14. What steps were taken by the Company prior to the issuance of the RFP?

Prior to issuance of the RFP, I&M (1) retained an Independent Monitor; (2) drafted the RFP based on the needs outlined in the Company's IRP; (3) assessed the pool of projects in the PJM approval process that would be eligible to bid into the RFP; and (4) engaged with stakeholders to gather input on the RFP's structure and requirements.

Q15. Please describe your role in the Company's 2022 All-Source RFP.

My role in the 2022 All-Source RFP was to oversee and facilitate the RFP process through its development, administration, evaluation, negotiation, and agreement execution phases for the Clean Energy Projects, which are the subject of this proceeding. I also served as the primary contact for coordination with the Independent Monitor and I&M throughout the process.

Q16. Please identify and explain the role of the Independent Monitor.

I&M retained Charles River Associates (CRA) to serve as the Independent Monitor on behalf of I&M for the All-Source RFP. As the Independent Monitor, CRA managed the RFP process and helped support the design and development of the RFP; led the stakeholder engagement process and feedback; conducted the Eligibility and Threshold (E&T) review for all proposals; and monitored the RFP administration from issuance to selection. CRA was also consulted post-selection to address emerging issues during contract negotiations, such as pricing changes due to supply constraints, to ensure the competitive procurement process was not compromised. Witness Koujak discusses CRA's role and experience as Independent Monitor in additional detail in his direct testimony.

Q17. How did the Company develop the structure and requirements of the RFP?

I&M worked in cooperation with the Independent Monitor to develop the RFP based on the overall capacity need identified in I&M's 2021 IRP submitted in January 2022 in Indiana and filed in February 2022 in Michigan. The RFP was developed to conform to requirements approved by the Commission order dated December 8, 2021 in Cause No. 45546[2] as well as the requirements of Michigan's *Competitive Procurement Guidelines for Rate-Regulated Electric Utilities* (MI Procurement Guidelines). The RFP was structured to be non-discriminatory and flexible with respect to technology, allow for project sizes as small as 5 MW, allow for stakeholder input in the development of the RFP prior to its issuance, and consider both third-party and utility ownership structures.

Q18. How did the Company collect and incorporate stakeholder input in the development of the RFP?

The Independent Monitor facilitated a stakeholder engagement process designed to provide stakeholders with an opportunity to provide input in the development of the RFP. The engagement effort allowed stakeholders to review the overall purpose, process, and schedule of the RFP, review RFP documents, and provide input to CRA and the Company.

Stakeholder communications were initiated early January 2022, notifying interested parties that I&M would be releasing an RFP in March 2022. CRA hosted an RFP website (imallsourcerfp.com) that shared information about the RFP development and issuance process, allowed for download of RFP documents and presentations, and provided contact information (phone/email) for sharing comments and suggestions directly with CRA. Stakeholder questions and responses were published on the website to ensure all participants had equal access to RFP information.

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[2] See Section A. 8 of Stipulation and Settlement Agreement for the 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 2.

On January 18, 2022 CRA hosted an RFP Development Meeting during which the structure of the RFP was shared and stakeholders were asked to provide initial comments to support the development of the Draft RFP. The Draft RFP was then released by CRA on January 28, 2022 followed by a Pre-RFP Stakeholder Meeting on February 8, 2022. Input from stakeholders during and following the Pre-RFP Stakeholder Meeting was received, responded to, and where reasonable, incorporated into the Final RFP that was issued on March 10, 2022 via the CRA website.

IV. Proposal Review and Project Selection

Q19. Please describe the initial bid receipt and overall bidder response to the 2022 All Source RFP.

All bids were submitted electronically to CRA on April 21, 2022 and shared with I&M. In total, CRA (and I&M) received 32 proposals from 12 unique bidders. Proposals included Solar, Wind, Solar plus Storage, Wind/Solar plus Storage, Thermal capacity resources, and standalone battery storage technologies. Several bidders submitted multiple bids for the same project (*e.g.,* bid variations with battery energy storage systems and multiple expected commercial operations dates), accounting for a greater number of bids than projects. A total of approximately 7,500 MW of proposed projects across 32 project bids were received.

Q20. Were proposals offered on an exclusive basis to the Company?

No. The proposals were not offered to the Company on an exclusive basis and the bidders could withdraw their proposal at any time.

Q21. Please outline the general process steps in the proposal review and project selection process.

The proposal review and project selection process involved the following general steps:

Step 1: Bid Clarification and Eligibility & Threshold (E&T) Review

Step 2: Detailed Analysis & Due Diligence

Step 3: Shortlist Identification and Negotiations

Step 4: Final Project Selection and Agreement Execution

Q22. Please describe the Bid Clarification process.

Upon receipt of proposals, the Company and the Independent Monitor reviewed the proposals for completeness. If information was either missing or unclear in a specific proposal, bidders were given the opportunity to provide clarifying information to the Independent Monitor and the Company to further evaluate the proposal. Initial bid clarification requests were compiled within a month of proposal receipt, primarily focused on verifying key E&T requirement information and pricing assumptions.

Q23. Please describe the E&T review.

An initial review of the proposals was conducted by the Independent Monitor to ensure all bids conformed with the E&T requirements listed in the 2022 RFP Section 9.1 (see Attachment TBG-1). The E&T requirements included criteria such as meeting the RFP target commercial operation date, minimum project size, location of proposed resources, interconnection status, and minimum design life.

The E&T review was conducted in parallel with the bid clarification process, ensuring that bidders were given reasonable opportunity to clarify inconsistencies or data gaps in their respective proposals. If a proposal did not reasonably meet any of the requirements of Sections 9.1.1 – 9.1.12 of the 2022

RFP, the proposal was deemed to be ineligible for further evaluation and the bidder notified accordingly. Further detail on this process is provided by witness Koujak.

Q24. Were any projects removed from further consideration that passed the E&T review?

Yes. Two of the three wind projects that had passed the E&T review ultimately rescinded their bids from the RFP to pursue other agreements. One of the projects subsequently entered into a PPA with an outside industrial customer. The other project was ultimately selected by I&M's sister company Appalachian Power Company. Appalachian Power Company had been reviewing the wind project before the I&M RFP was released and ultimately selected the project after completing the detailed bid analysis phase.

Q25. Please describe the Detailed Analysis portion of the RFP process.

Those projects that passed the E&T review underwent a detailed analysis, continuing due diligence, and evaluation (scoring) process conducted by a multidisciplinary team of knowledgeable industry professionals from AEP, I&M, and select outside consultants.[3] Team members had specific expertise in each of the non-price factor topics with backgrounds in engineering, project management, operations and maintenance, real estate, economic development, wind and solar resource assessment, transmission planning, environmental science and permitting, energy economics and modeling, and contract law.

The multidisciplinary team conducted the Economic Analysis (further summarized below), which accounted for 60 points (60%) of the proposal's total score, and the Non-Price Analysis, which accounted for 40 points (40%) of the proposal's total score. The two scores were then combined to determine an overall score for each bid. All scores were reviewed by the Independent Monitor

[3] Outside consultants included: DNV, Inc., for third party evaluation of the solar resource information; Simon Wind, for third party evaluation of the wind resource information; and HDR, Inc. for support conducting an environmental and social justice assessment of each project.

for reasonableness and consistency. The detailed analysis process allowed the Company to objectively evaluate and rank each eligible bid, which informed the decision to move forward with negotiations and further due diligence on the proposals.

Q26. What were the components of the Economic Analysis?

The Integrated Resource Planning team completed the Economic Analysis for each of the proposals that met the E&T requirements. The analysis included inputs directly from the proposals, such as the bid price, interconnection costs, and term length. It also included various inputs from the interdisciplinary team such as transmission congestion and line loss estimates, estimated operation and maintenance costs, and other operating company specific modeling variables such as applicable federal tax credits and financing assumptions. The Economic Analysis resulted in several key price metrics that were used to determine the ultimate price score for each of the proposals. A more detailed description of the Economic Analysis, price metrics, and price scoring can be found in Company witness Becker's testimony.

Q27. How was pricing compared across different proposal contract types, with different term lengths, and different energy product offerings in the Economic Analysis?

Price comparisons across proposals with different contract types, technologies, and term lengths were facilitated through a two-phased process focused on three price-based metrics. The first phase (Phase 1) of the Economic Analysis focused on the assessment and comparison of projects of similar generation type (wind, solar, or supplemental capacity) using either a calculated Levelized Adjusted Cost of Energy (LACOE) or Levelized Adjusted Cost of Capacity (LACOC) metric. The second phase (Phase 2) then assessed and compared the projects across all technology types based on a Value to Cost (V/C) ratio. The V/C ratio allowed for the holistic consideration of all the value streams provided by each generation type in the comparison. Across both phases, the metrics were calculated in a manner that ensured proposals could be compared on an equivalent basis across the range of technology types, contract structures (PSA or PPA), contract term lengths, and energy product offerings.

Ultimately, given the number of projects remaining after the E&T analysis, the Independent Monitor and I&M agreed that no project would be eliminated in the first phase and all eligible projects would proceed from Phase 1 (LACOE/LACOC) to Phase 2 (V/C) comparisons. A more detailed review of the economic analysis and scoring can be found in the Direct Testimony of Witness Becker.

Q28. What non-price factors were considered in the evaluation of each of the proposals?

A total of ten non-price factors grouped into four categories were considered in the evaluation of each proposal. The four categories each accounted for up to ten points of the total non-price score of each bid. The categories are described below with respect to the individual non-price factors considered in each.

The Asset-Specific Benefits and Risks category included two factors, 1) the *Contract Term/Asset Life-Related Market Risks* factor, and 2) the Ownership Optionality and Flexibility Benefits factor. Overall, this category evaluated the project configuration and contract terms of the proposals with respect to operational flexibility and performance expectations of the resource, while also considering the potential for increased exposure of the Company to future market volatility.

The Development Status and Risks category included two factors, the 1) *Development Status, Interconnection Status, and Other Project Completion Risks* factor, and the 2) *Project Timing* factor. This category assessed each project with respect to its potential to meet its proposed commercial operation date, its interconnection progress, and any notable material supply risks. It also awarded points to those projects that could be available for the 2025-2026 capacity year.

The Environmental, Social, and Economic Impacts/Benefits category was comprised of three factors, 1) the *Carbon Emissions* factor, 2) the *Environmental and Wildlife Impact / Permitting* factor, and 3) the *Economic Stimulus Benefits, Community Support, and Supplier/Contractor Diversity* factor. Together these factors assessed the overall impact on communities, inclusive of considerations for natural and/or historic resources, environmental and social justice, and local zoning or permitting approvals. The Company engaged a third-party consultant HDR, Inc. to assist with the environmental and social justice analysis. This category also included consideration of potential community benefits such as the potential for increased value to (or use of) local businesses, economic development, and the developer's plan to use small and diverse suppliers and subcontractors, and/or contractors based in Indiana or Michigan.

The Proposal and Project Quality category was also comprised of three non-price factors: 1) *Bidder Experience and Financial Wherewithal* factor; 2) *Exceptions to AEP Generation Facility Design Standards* factor; and 3) *Exceptions to Form PSA or PPA* factor. Together, these factors evaluated the overall experience of the developer, their financial status, and their willingness to adhere to AEP's design and contracting expectations.

Q29. Please provide a summary of the total scores for all the eligible proposals.

Once the economic and non-price evaluations were completed and reviewed by the Independent Monitor for consistency and completeness, the scores were combined to yield a Total Score for each bid. Total scores for all the eligible bids ranged from roughly 55 to 93 out of 100. A full report of the price and non-price scores for each of the eligible bids is provided in the Bid Score Sheet, Attachment TBG-2C. Further discussion on the selection process and rationale are provided by Witness Koujak.

Q30. What projects were selected for detailed contract negotiations (shortlist)?

The Company selected the lowest reasonable cost facilities that best met the energy and capacity needs of the Company. A total of seven project proposals were selected for further shortlist contract negotiations. Ultimately, five of the seven projects were successfully negotiated. These projects are represented in Table TBG-2 above, and include two solar PPAs, two solar PSAs, and a capacity-only contract from an existing gas facility.

V. Negotiation Process and Market Pressures

Q31. Describe the contract negotiation activities with the developers of the Clean Energy Projects.

The Company began commercial contractual negotiations once the parties were formally notified that their bids were selected for shortlist negotiations. Due diligence efforts contained in this phase focused on further review and assessment of each project's site development plans, land agreements, and local approval status, grid interconnection studies and status, as well as continual refinement of the engineering studies, design expectations, and construction scope of work to support negotiations. Formal commercial and contractual discussions included regular focused discussions on key contract terms as well as ongoing commercial discussions as design requirements, the construction scope of work, and contract terms were finalized.

Ultimately, the Company was successful in executing agreements for the Clean Energy Projects and one capacity-only contract following shortlist negotiations. The four Clean Energy Projects negotiated through this process are presented herein which agreements are included in I&M Attachments TBG-3 and 3C through TBG-6 and 6C.

Q32. Why were two projects removed from further consideration during shortlist negotiations?

Two shortlisted projects were ultimately removed from further consideration as a result of new information that arose during additional due diligence and ongoing discussions during contract negotiations.

A standalone storage project was initially selected for its capacity-only bid. However, upon further review of the project, I&M determined that [redacted]

A solar project was ultimately removed from further consideration due to [redacted]

Q33. Did any of the projects change during the shortlist negotiation process?

Yes. The majority of projects that bid into the RFP were early in their development, with many of the key design, construction, and procurement decisions still outstanding in the normal course of a project development timeline. During the roughly eight-month period from when proposals were shortlisted until contracts were negotiated, bidders continued with the development efforts that are typical for renewable energy projects at this stage in their development. In some cases, ongoing landowner discussions, local approvals, and final material and equipment selection [redacted] In parallel with these efforts, developers responded to an array of market pressures and rule changes [redacted]

Q34. How did market pressures impact the RFP bid and review process?

Developers submit bids into the RFP with cost estimates that are backed by a range of both explicit and implied assumptions about material supply chains, contracting costs, design expectations, and the legal and regulatory framework understood at the time of submittal. However, markets change as time passes, and it can take up to a year to complete the process from bid submittal to contract execution and additional time beyond that to obtain regulatory approval. [redacted]

Q35. What market pressures influenced the bids received in response to the 2022 All Source RFP?

A range of events impacted markets both immediately before and during the bid selection and negotiation process for the 2022 All Source RFP, including: the Uyghur Forced Labor Prevention Act (UFLPA) and subsequent detainment of module deliveries by U.S. Customs and Border Protection, Russia's invasion of Ukraine, the initiation of the Antidumping Duty and Countervailing Duty (AD/CVD) investigation by the U.S. Department of Commerce (Commerce), the enactment of the Inflation Reduction Act (IRA), the release of guidance around the IRA's Prevailing Wage and Apprenticeship requirements, PJM interconnection queue reform, and the rise in inflation and interest rates. Each of these events added a level of market uncertainty to underlying project material and labor costs, schedules, compliance requirements, and finance costs [redacted]

Q36. Which market pressures had the most impact on project schedules?

Ongoing supply chain risks and delays in the PJM interconnection process have been the primary drivers of schedule changes during the bid review and negotiation process. Continuing supply chain risks and commodity inflation driven by the war in Ukraine, pending solar module tariff outcomes of the AD/CVD investigation, and competition among developers for material supply and contractor support have all added scheduling risks to projects.

However, delays and uncertainty in the PJM interconnection process have likely had the most significant impact on project development timelines. Generation interconnection requests have more than tripled since in the last several years.[4] This rapid increase in queue volume has caused significant delays, increasing the time required for acquiring an executed interconnection agreement from a little over two years in 2015 to nearly five years today. The extended timeline has been problematic for developers since many projects face financial uncertainty until the interconnection study process can identify the scope and cost of network upgrades that are required for the project to come online.

The overall effect of the PJM queue delays has been a reduction in the supply of projects that can support the increasing demand for renewables in a manner that meets the timing of energy and capacity needs of the system. Although FERC has approved reforms to help resolve the generation interconnection queue bottleneck, the plan itself will take years to execute and new generation interconnection requests are no longer being accepted until more of the backlog is processed.

Q37. What market pressures and/or economic factors affected commodities, equipment, and labor costs?

A range of economic factors caused increases to cost and volatility in raw materials, equipment costs, interest rates, and labor during the bid evaluation and negotiation process. Each of these factors impacted bid pricing and shaped contract negotiations.

[4] PJM, 2022. PJM Members Endorse Plans to Revamp and Improve the Generation Interconnection Process. https://www.pjm.com/-/media/about-pjm/newsroom/2022-releases/20220427-pjm-members-endorse-plans-to-revamp-and-improve-the-generation-interconnection-process.ashx

Raw materials, including steel and aluminum, continue to see higher pricing and volatility driven by lingering impacts of the pandemic, the war in Ukraine, inflation, and the energy crisis in Europe. As an example, early in 2022, the Hot Rolled Coil (HRC) steel index[5], which generally fluctuated between $500 – $800 per ton in the years preceding the pandemic, rose from $1,000 to $1,500 per ton driven by Russia's invasion of Ukraine (the two countries together account for nearly 50% of the world's pig iron, a key component in steel production). Although prices declined in the latter half of the year, steel prices (at the time of this testimony) have risen again to nearly $1,200 per ton displaying a combination of high pricing and volatility that continue to impact supplier pricing for steel products which directly affect solar racking, tracking and piling systems.

The solar module industry has been impacted by a range of regulatory changes, investigations, uncertainty, and supply challenges that have driven up pricing and slowed solar deployments. The UFLPA signed into law in late 2021, resulted in significant bottlenecks at U.S. ports in mid-2022 as Customs and Border Protection (CBP) officials worked through compliance reviews on a growing backlog of shipments. Soon after, Commerce initiated an investigation to determine if the United States should impose additional antidumping/countervailing duties (AD/CVD) on imports of solar cells and modules coming from Cambodia, Malaysia, Thailand, and Vietnam. The investigation stems from claims that Chinese companies were attempting to circumvent current U.S. AD/CVD tariffs by performing a minor production step in these countries. A preliminary determination in the investigation was released in late 2022 that suggested certain suppliers from the four countries could be assessed duties of between 15-240% on their modules (87 FR 75221). Together, these actions have both increased schedule concerns around solar module delivery and added uncertainty around solar module pricing.

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[5] S&P Capital IQ Pro Website, Steel – Domestic Hot Rolled Coil (CME-NYMEX) data. Accessed March, 24 2023. S&P Global Market Intelligence, 55 Water Street, New York, NY 10041

Rising inflation driven by an array of pandemic-related factors in 2021 led to an increase in interest rates. This, in turn, has affected project finance costs, reduced the ability of developers to attract tax equity financing[6], and further exacerbated pricing impacts from ongoing supply chain challenges. Though inflation is on a slow decline, uncertainty around Federal Reserve actions and effect on interest rates continues to be a concern for bidders.

The IRA, passed in August of 2022, included an array of benefits for renewable deployment. The extension and expansion of renewable energy tax credits resulted in a boom of planned development, with new planned renewable deployments increasing significantly since its enactment. However, the impacts of the IRA benefits on pricing are less abrupt than many had hoped. The surge in demand for new projects has been met with lingering supply chain challenges, tariff risks and uncertainty, generation queue backlogs and new labor requirements [redacted]

Q38. Do you see these market challenges [redacted]?

[redacted] As things stand today, the queue reform process will take several years to implement and the ultimate outcome of that process will continue to be highly dependent on the volume of projects that are submitted to PJM for processing and the success of those projects in reaching commercial operation.

[6] Sweeney, 2023. Renewable project financing to rebound in 2023 as energy transition accelerates. S&P Global Commodity Insights. S&P Global Market Intelligence, 55 Water Street, New York, NY 10041

With 40 GW of thermal resources expected to retire in the near future[7], the number of interconnection requests is reasonably expected to increase. Driven by carbon goals and the tailwinds of the IRA, the retirements are largely expected to be replaced by intermittent and limited duration (storage) resources that require many more projects to replace each MW of capacity of a single thermal generation facility. New projects can also face local permitting and approval challenges with some stalling or failing before reaching a signed interconnection agreement. Projects that ultimately make it through the interconnection process will need to efficiently manage through the supply chain, labor challenges, and other market stressors I've described previously to reach commercial operation.

[redacted]

Q39. Please elaborate on how the Company has responded to the industry challenges described above through contract negotiations.

As discussed above, recent supply chain disruptions, inflation, regulatory uncertainty, and other market pressures have impacted the energy industry and the world economy in general. These challenges are ongoing and will continue to impact the development and deployment of new generation needed to support the company's near-term capacity needs.

[redacted]

[7] PJM, 2023. PJM Details Resource Retirements, Replacements and Risks | PJM Inside Lines. https://insidelines.pjm.com/pjm-details-resource-retirements-replacements-and-risks/

[redacted]

As shown in the following section, each agreement also incorporates financial assurances that the developer will meet its contractual obligations; that the facilities will align with performance expectations; and that major equipment suppliers and contractors will honor all warranties, guarantees, and commitments to the projects.

Overall, the Company's [redacted] Best Estimate is reasonably designed [redacted] allowing the Company to acquire the resources needed to meet our customers' need for energy and capacity resources.

VI. Overview of the PSAs

Q40. Please describe the PSA structure and key components of the PSAs.

The PSA governs the construction of the selected facilities by the developers and establishes the overall framework within which the Company and the developer engage throughout the design, construction, commissioning, and purchase of the equity interests of the project holding companies, as well as any rights or warranties that remain in effect after completion of the project.

The PSA document is organized by topical sections that present defined contract terms, process steps for engagement at major project development milestones, as well as the rights, requirements, and responsibilities of each party throughout the life of the agreement. Table TBG-3 provides a summary of each major section of the PSA and its overall purpose.

Table TBG-3 – Major PSA Components and Purpose	
Definitions and Rules of Interpretation	Establishes the agreed upon terms and rules for interpretation of those terms within the construct of the agreement
Purchase and Sale of Purchased Interests	Describes the assets to be purchased, the mechanics of the closing process, the purchase price, and process in the event of force majeure or major changes in law
Conditions Precedent (CP); Notice to Proceed/Firm Date	Establishes the conditions that must be met (requirements) of both parties to move forward with the project post-regulatory approval
Development and Construction Covenants, and Other Pre-Closing Covenants	Pledges made by each party regarding the conduct of the project development and construction effort, including coordination and reporting rules, codes of conduct, etc.
Representations and Warranties	Statements by each of the parties that they must assure are true and accurate regarding key conditions, facts, and circumstances with respect to the parties involved and the project
Conditions Precedent (CP) to Closing for Buyer and Seller	Establishes the conditions that must be met (requirements) of both parties to finalize the purchase of the project (by I&M) and sale of the project by the developer
Post-Closing Covenants	Pledges made by each party pursuant to engagement between the parties that extend after the closing is complete
Indemnification and Termination	Contract terms outlining the survival period of project associated liabilities, process for handling disputes and claims between the parties, and any limitations on claims that can be made of either party

Q41. Please describe the overall structure of the Lake Trout PSA and key terms of the agreement.

The Lake Trout PSA provides the commercial structure, procedural rules, rights, and responsibilities of and for the Company to acquire 100% of the equity interests of Lake Trout Solar, LLC, a project holding company which owns the to be constructed 245 MW Lake Trout Solar Project in Indiana. The following bullets outline key components of the agreement and the project:

- The Purchase Price, a component of the Best Estimate of the project, is [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]

- [redacted]
- [redacted]
- [redacted]
- [redacted]

[redacted]

[redacted]

Q42. What are the requirements for reaching Firm Date in the Lake Trout PSA?

Firm Date is the date on which EDF and the Company have met a series of CPs to authorize the advancement of construction activities and commit the Company to future payment and receipt of the facility once the project is completed. The Firm Date is similar to a Notice to Proceed (NTP) date under other similar agreements.

Each party must either achieve the prescribed CPs, or waive the requirement for the project to move forward into the final design and construction phase. Typical CPs included in the Lake Trout PSA include: having an approved site plan, certificates that the representations and warranties made by Buyer and Seller are true and correct, agreed upon insurance coverages and credit support, and that this Commission has approved the project for cost recovery. A complete list of the CPs to Firm Date are shown in sections 3.1-3.4 in the Lake Trout PSA.

Q43. Does the Lake Trout PSA include [redacted]?

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Q44. How did the Company [redacted] for the Lake Trout Solar Project?

[redacted]

Q45. Please summarize the general closing conditions in the Lake Trout PSA.

The closing of the Lake Trout PSA will occur when certain closing conditions have either been met or waived by the appropriate party to the PSA. The closing conditions in the Lake Trout PSA [redacted]

- [redacted]
- [redacted]

- [redacted]
- [redacted]

[redacted]

Q46. [redacted]

[redacted]

Q47. Please describe the overall structure of the Mayapple PSA and key terms of the agreement.

The Mayapple PSA provides the commercial structure, procedural rules, rights, and responsibilities of and for the Company to acquire 100% of the equity interests of Mayapple Solar, LLC, a project holding company which owns the to be constructed 224 MW Mayapple Solar Project in Pulaski County, Indiana. The following bullets outline key components of the agreement and the Project:

- The Purchase Price, a component of the Best Estimate of the project, is [redacted]

[redacted]

- [redacted] The NTP date is the date by which I&M and Lightsource bp have confirmed that they have met all required CPs to NTP and final project design and construction can commence. I&M's principal CP to NTP is that all Indiana Utility Regulatory Commission (IURC) and Michigan Public Service Commission (MPSC) approvals have been received for the project. Lightsource bp's principal CPs to NTP require that key local approvals and interconnection agreements have been received and major contracts with material suppliers and construction contractors have been executed for the Project.

- [redacted]

- [redacted]

- [redacted]

- [redacted]
- [redacted]

Q48. What are the CPs for reaching NTP in the Mayapple PSA?

Reaching NTP provides Lightsource bp and I&M the authorization under the PSA to advance activities into the major construction phase of the facility and commits the Company to future payment and receipt of the projects once each of the projects are completed. Typical CPs in the Mayapple PSA include: having obtained necessary state commission approvals, FERC approvals, a finalized site plan, certificates that the representations and warranties made by Buyer and Seller are true and correct, and agreed upon insurance coverages and credit support. A complete list of the CPs to NTP are shown in Section 3.10 in the Mayapple PSA.

Q49. Does the Mayapple [redacted]?

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Q50. Please summarize the general closing process contained in the Mayapple PSA.

The closing of the Mayapple PSA will occur when certain closing conditions have either been met or are waived by the appropriate party to the PSA. The closing conditions in the Mayapple PSA include that Lightsource bp has:

- [redacted]
- [redacted]
- [redacted]
- [redacted]

[redacted]

Q51. How do the PSAs address the Prevailing Wage and Apprenticeship (PWA) requirements contained in the recently enacted Inflation Reduction Act (IRA)?

Both projects will be developed in a manner that is compliant with the PWA requirements under the IRA to ensure that I&M's customers will benefit from the full value of the PTCs. Several contract provisions were negotiated to ensure that PWA compliance is met, including:

- [redacted]
- [redacted]
- [redacted]

Q52. Do the PSAs contain liquidated damages or financial assurances that the developers will meet their obligations?

Yes.[redacted]

[redacted]

VII. Overview of the PPA Agreements

Q53. Please provide an overview of the Clean Energy PPA agreements.

I&M entered into two Clean Energy PPA agreements with separate developers, also shown in Table TBG-2. The Clean Energy PPAs provide I&M with rights to the production attributes of the renewable resources for the term of the contract including capacity, RECs, and energy.

Q54. Please describe the structure and terms of the Elkhart County Solar Project.

The Elkhart County Solar Project is a 100 MW solar project under development by Savion, located in Elkhart County, Indiana. The Project has an expected commercial operation date of December 31, 2025 upon which date, I&M will purchase all of the renewable energy produced by the facility for a term of 30 years at a [redacted]. The following are several key features of the Elkhart County PPA:

- Savion, LLC will initiate the construction phase of the project upon receipt of a final non-appealable order from both the IURC and the MPSC.
- The Commercial Operation Date is December 31, 2025, [redacted]
- The Project has a PJM AE2 queue number and no identified network upgrade responsibilities.

- The PPA provides for [redacted].
- [redacted]
- [redacted]
- [redacted]
- [redacted]

Q55. [redacted]

[redacted]

[redacted]

[redacted]

Q56. Does the PPA with Savion provide any financial assurances that Savion will meet its obligations under the PPA?

Yes. [redacted]

Q57. Please describe the structure and terms of the Sculpin Solar Project.

The Sculpin Project is a 180 MW solar project under development by EDF located in Dekalb County, IN. The Project has an expected commercial operation date of December 15, 2025 upon which date, I&M will purchase all of the renewable energy produced by the facility for a term of 30 years at a [redacted]. The following are several key features of the Sculpin PPA:

- EDF will initiate the construction phase of the project upon I&M's receipt of a final non-appealable order from both the IURC and the MPSC [redacted]ial [redacted]
- The Commercial Operation Date is December 15, 2025, [redacted]

- The PPA provides for a [redacted].
- [redacted]
- [redacted]
- [redacted]
- [redacted]

Q58. [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Q59. Does the PPA with EDF provide any financial assurances that EDF will meet its obligations under the PPA?

Yes. [redacted]

VIII. Best Estimates of PSA Project Costs.

Q60. What is the Company's best estimate of total installed capital costs of the Lake Trout Project at completion?

The Best Estimate for the Lake Trout total installed capital cost is identified by component in Figure TBG-3 below.

Figure TBG-3

TOTAL INSTALLED CAPITAL COST	
	Lake Trout 245 MW Solar
PSA Price	
[redacted]	[redacted]
[redacted]	[redacted]

Owner's Costs	[redacted]
Resiliency & Integration	
Project Management	
Other Owner's Costs	
Acquisition and Development	[redacted]
Overheads	
AFUDC	
Project Contingency	[redacted]
Total Facility Cost	[redacted]

Q61. What is the Company's best estimate of total installed capital costs of the Mayapple Project at completion?

The best estimate for the Mayapple Project total project installed cost is identified by component in Figure TBG-4 below.

Figure TBG-4

TOTAL INSTALLED CAPITAL COST	
	Mayapple 224 MW Solar
PSA Price	
[redacted]	[redacted]
Owner's Costs	
Resiliency & Integration	[redacted]
Project Management	
Other Owner's Costs	
Acquisition and Development	[redacted]
Overheads	
AFUDC	
Project Contingency	[redacted]
Total Facility Cost	[redacted]

Q62. What are the component costs included in the Best Estimate?

The Best Estimate of the total installed capital costs includes: the PSA Price, Owner's costs, and a Project Contingency. I summarize each of these components below.

The PSA Price reflects the cost of the negotiated purchase price between the Company and the Developer for the engineering, procurement and construction of the Clean Energy PSA Projects, including base interconnection costs [redacted]

Owner's Costs can be broken into two general categories: those associated with construction oversight, engineering/design reviews, and the physical integration of the project into I&M operations, and; those incurred by the Company for the identification and acquisition of the project (i.e. the RFP process, due diligence, and fees associated with negotiations and regulatory process). A more detailed description of what costs are included in the description of owner's costs is found in Company witness Lozier's testimony.

Lastly, the Best Estimate of the total installed capital costs also includes a project contingency. The Project Contingency includes cost consideration for typical risks that often occur during the development and construction stages of large infrastructure projects.

Q63. Why is a contingency included in the Best Estimates?

For projects the size and complexity of the Clean Energy PSA Projects, and for projects that will not be placed in service for several years from the date this testimony will be filed, it is impractical to believe that no new issues or challenges will arise through the course of the project's final development, design, and construction. To address this reality, a contingency budget was developed using a combination of identified project-specific risks and a reasonable allocation of funds for unidentified risks based on projects of similar size, type, and complexity. For each identified risk, the cost to mitigate the risk was evaluated. The contingency assessment for each Project is provided in my workpapers: WP-TBG-1C – Risk Register for Lake Trout PSA Project (Confidential/Highly Competitively Sensitive); WP-TBG-2C – Risk Register for Mayapple PSA Project (Confidential/Highly Competitively Sensitive).

How was the Project Contingency estimate developed?

The Project Contingency was developed through an iterative process that began upon project selection for shortlist negotiations. At the outset of negotiations, I&M and the developer engaged in an in-depth due diligence process that expanded on the information collected during the project selection effort. In parallel, the two parties engaged in the negotiation of the PSA itself, working through key agreement terms to come to mutual resolution.

Through these two parallel and interrelated efforts, a range of potential project issues and risks were identified and tracked. Some risks were resolved by proposing changes to the project design, removing a proposed supplier, or simply gaining a greater understanding of the issue, while others were resolved through negotiations of the terms of the PSA, Scope of Work, or other associated documents.

Those issues that were not eventually resolved were qualitatively assessed by project SMEs to determine the level of risk the issue posed to the project. The highest risk issues from this qualitative assessment served as the primary source of information for compilation of the project Risk Registers (See WP-TBG-1C – Risk Register for Lake Trout PSA Project (Confidential/Highly Competitively Sensitive); WP-TBG-2C – Risk Register for Mayapple PSA Project (Confidential/Highly Competitively Sensitive). The Risk Registers, in turn, served as the basis upon which an overall Project Contingency was calculated.

Reasonable contingency levels were calculated for each of the major risk areas identified in the Risk Registers. The pricing evaluations considered a range of information from industry sources (e.g. market indexes, industry trend reports, recent bid results, etc.) developer provided inputs, and the professional experience and judgements of our SMEs.

Q64. What types of risks were considered in the Project Contingency?

The Project Contingency included consideration of [redacted]

[redacted]

[redacted]

Q65. What risks comprised the major portions of the Project Contingency?

[redacted]

[redacted]

Q66. In your opinion, are the estimated costs of the PSA Projects reasonable?

Yes. The PSA costs are the result of the competitive All-Source RFP process and direct arms' length negotiation and executed transactions as discussed above. Respondents to the RFP were motivated to reply with competitive bids in order to be considered for review and negotiation of an agreement. It was commercially practicable to secure the estimated costs of the PSA Projects in this manner. The inclusion of the potential cost impact of project risk and factors beyond the Company's control provides Best Estimates that reasonably address industry challenges, and is reasonably designed to manage the timely development of the Projects. This is particularly appropriate given recent and ongoing economic conditions, and better positions the Company, Commission, and stakeholders to assess the Project costs at the time the Projects are presented for pre-approval.

IX. Summary and Conclusion

Q67. Please summarize your testimony and conclusions.

The agreements for the purchase of the renewable resources and energy output presented in my testimony are the result of a competitive RFP process, arms' length negotiation, reasonably reflect change of law and supply chain disruptions and other economic conditions and are consistent with industry practice. The Project costs reasonably reflect industry trends and the potential cost impact of project risk and factors beyond the Company's control. The agreement terms are reasonably designed to manage industry and economic challenges while facilitating the capacity and energy resources required by the Company to meet its customers' ongoing need for electricity. Therefore, the Commission should approve these agreements and the Best Estimate for each Clean Energy PSA so that the Company may move forward with the development of these Clean Energy Projects.

Q68. Does this conclude your pre-filed verified direct testimony?

Yes, it does.

VERIFICATION

I, Timothy B. Gaul, Director – Regulated Infrastructure Development at American Electric Power Service Corporation, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information, and belief.

Date: 3/23/23

Timothy B. Gaul

I&M Exhibit: _____

INDIANA MICHIGAN POWER COMPANY

PRE-FILED VERIFIED DIRECT TESTIMONY

OF

BARTLEY TABERNER

Content

DIRECT TESTIMONY OF BARTLEY TABERNER
ON BEHALF OF
INDIANA MICHIGAN POWER COMPANY

I. Introduction of Witness

Q1. Please state your name and business address.

My name is Bartley Taberner. My business address is 8600 Smiths Mill Road, New Albany, Ohio 43054.

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

I am employed by the American Electric Power Service Corporation (AEPSC) as a Transmission Planning Manager for East Transmission Planning in AEPSC's Grid Solutions group, (Grid Solutions). AEPSC is a shared services organization that allows American Electric Power (AEP) to achieve economies of scale and provide operational expertise and efficiencies in the provision of engineering, financing, accounting, planning, advisory, and other services to the subsidiaries of the AEP system, one of which is Indiana Michigan Power Company (I&M or the Company).

Q3. Briefly describe your educational background and professional experience.

I received a Bachelor of Science – Electrical Engineering degree from West Virginia University in Morgantown, WV. I joined AEP in 1987 as a Distribution Engineer in the Huntington, WV division of Appalachian Power Company. In 1992 I joined the Marketing and Customer Services organization and spent over nine years as a Power Engineer and Key Account Engineer. In 2001, I joined the East Transmission Planning Department and was promoted to Senior Engineer in 2006 and Supervisor in 2008. In 2010, I was promoted to the position of Manager, Transmission Business Development with responsibilities for the Potomac -Appalachian Transmission Highline (PATH) project. I returned to Transmission Planning in 2011 as Manager of Compliance, Modeling and Process Development. I moved to my current position as I&M Transmission Planning Manager in 2016. I am a licensed professional engineer in the state of Ohio.

Q4. What are your responsibilities as a Transmission Planning Manager?

My responsibilities include transmission planning activities in Indiana and Michigan for I&M and AEP Indiana Michigan Transmission Company (IMTCO). I&M and IMTCO are in the AEP Zone of PJM LLC (PJM) Regional Transmission Organization (RTO)[1]. For ease of reference, these subsidiaries will collectively be referred to as I&M in this testimony.

II. Purpose of Testimony

Q5. What is the purpose of your testimony?

The purpose of my testimony is to support the Company's request for approval of four solar projects consisting of two purchase sale agreement (PSA) projects and two purchase power agreements (PPA) (collectively the Clean Energy Projects), by explaining the Clean Energy Projects' transmission interconnection to the PJM RTO. In addition, I will address the costs of these interconnections. I am also presenting, with input from Company witnesses David Lucas, Mark Becker and Timothy Gaul, the Company's response to the Indiana Utility Regulatory Commission's (IURC or Commission's) General Administrative Order (GAO) 2022-01, which became effective August 1, 2022.

[1] IMTCO also has an investment in a switchyard in Greentown IN that is in the Midcontinent Independent System Operator RTO.

Q6. Where are the PJM Interconnection System Impact Study Reports for the Clean Energy Projects accessible?

The links to the PJM Generation Interconnection System Impact Study Reports, by project, are listed in Table BT-1:

Table BT-1: List of Projects

Project Name	PJM Queue Number	Generation Interconnection System Impact Study Reports
Lake Trout (PSA)	AF1-119, AF2-162[2]	https://www.pjm.com/pub/planning/project-queues/impact_studies/af1119_imp.pdf https://www.pjm.com/pub/planning/project-queues/impact_studies/af2162_imp.pdf
Mayapple Solar (PSA)	AG1-349	https://www.pjm.com/pub/planning/project-queues/impact_studies/ag1349_imp.pdf
Elkhart County (PPA)	AE2-323	https://www.pjm.com/pub/planning/project-queues/impact_studies/ae2323_imp.pdf
Sculpin (PPA)	AF1-091	https://www.pjm.com/pub/planning/project-queues/impact_studies/af1091_imp.pdf

Q7. Are you sponsoring any Attachments?

Yes. As previously noted, I, along with Company witnesses Becker, Lucas, and Gaul, co-sponsor two attachments that demonstrate compliance with the requirements specified in Appendix A to the GAO 2022-01 for the Clean Energy Projects' approvals requested in this application:

[2] Lake Trout project has two queue numbers because after the original request for interconnection was made (AF1-119) the developer requested additional generating capacity that, per PJM requirements, required an additional queue position to study the increased capacity (AF2-162). The links to the System Impact Studies for both queue numbers have both been included in Table BT-1.

Attachment	GAO 2022-01 Requirement	Project Name
Attachment BT-1	Support for certificate of public convenience and necessity (CPCN) projects submitted pursuant to Ind. Code ch. 8-1-8.5.	Lake Trout Mayapple
Attachment BT-2	Support for PPA projects submitted pursuant to Ind. Code ch. 8-1-8.8.	Elkhart County Sculpin

Q8. Were the attachments that you co-sponsor prepared by you or under your direction or supervision?

Yes.

III. PJM Generation Interconnection Process

Q9. What RTO will these projects be connected to?

The Clean Energy Projects will all be connected to PJM.

Q10. Please discuss the interconnection approval process of these projects.

The PJM RTO has the responsibility for planning the expansion and enhancement of the PJM Transmission system on a regional basis. As such, PJM defines the interconnection process.[3] New generation interconnections that are designated in whole or part as a Capacity Resource or Energy Resource must enter the PJM New Services Queue.

[3] PJM Manual 14A: New Services Request Process: m14a.ashx (pjm.com); PJM Manual 14G: Generation Interconnection Requests: m14g.ashx (pjm.com).

Q11. Please further describe the PJM New Service Queue.

When a New Service Request is submitted to PJM, it is entered into the New Service Queue that is open at the time of the submittal. There are two six-month queue periods per year: period one, which starts on October 1 and closes on the following March 10, and period two, which opens April 1 and closes on the following September 10.[4] All projects submitted in a particular window will be assigned to that queue and the impacts of the project will be evaluated individually and in conjunction with all other projects in that queue. As an example, for the Lake Trout queue numbers shown above, AF1-119 entered the queue on September 13, 2019, and AF2-162, entered the queue on March 16, 2020. Hence, AF1-119 is in the period one queue, and AF2-162 is in the period two queue.

Q12. Please describe the process PJM follows for evaluating projects.

The developer of the project initiates the connection of a proposed generation facility to the transmission system by submitting a New Service Request to PJM, which will be assigned to the relevant New Service Queue as explained in Question 11 above. Based on this request, PJM will prepare an initial Feasibility Study to assess the practicality and cost of integrating the generation into the PJM system. If the study supports the project, PJM will, based on an executed agreement with the customer (developer), prepare a System Impact Study to analyze the connection and determine any ramifications or issues that would need to be addressed if the project were to be constructed. Finally, if the System Impact Study determines the interconnection can proceed, then a Facilities Study is performed that focuses primarily on the design and cost of facilities necessary to physically connect the generation to the transmission

[4] Projects dated subsequent to September 10 but before October 1 are considered in the Period 1 queue, and projects dated subsequent to March 10 but before April 1 are consider in the Period 2 queue.

system. Construction of the interconnection point will be managed by the transmission owner, in this case AEPSC on behalf of I&M.

Q13. Does I&M participate in this process?

Yes, as the transmission owner. While PJM is responsible for the required analysis, they will consult with the transmission owner during the process. In addition, while PJM will identify the improvements necessary for a successful generation interconnection, the required facilities will, as described above, be designed with I&M's input and must meet I&M's technical specifications.

Q14. Have estimates of the required interconnection costs for each Clean Energy project been developed?

The Generation Interconnection System Impact Study Reports (shown in Table BT-1 above) include a cost estimate for each project. As noted therein[5], these studies are subject to revisions due to subsequent engineering studies and on-site reviews to determine final construction requirements. In addition, there may be a need for a Federal Income Tax gross up adjustment based on whether the project meets certain Internal Revenue Service requirements. Finally, stability analysis performed during the development of each project's Facilities Study may identify additional upgrades not considered in the System Impact Study Report. These costs are taken into consideration in the PSA Clean Energy Project's Best Estimates and risk registers sponsored by Company witnesses Lozier and Gaul. The status of the Facilities Studies are discussed later in my testimony. Company witness Gaul also discusses the interconnection costs of the PPA Clean Energy Projects.

[5] See the "Cost Summary" Section in the Generation Interconnection System Impact Study Reports for Lake Trout, Mayapple Solar, and Sculpin at ¶5 and Elkhart County at ¶2.2.

IV. Status of Projects in the PJM Interconnection Queue

Q15. Have interconnection requests been made for these projects?

Yes. The interconnection requests have been submitted to PJM. The respective queue numbers are listed in Table BT-1 presented previously in this testimony.

Q16. Please discuss the status of these requests.

Feasibility and Generation Interconnection System Impact Study Reports have been completed and links to the latter on the PJM website are provided in Table BT-1. All requests are currently in the Facilities Study stage of the PJM process. The Facilities Studies reports for these projects will be issued by PJM upon completion of the respective studies.

Q17. What factors impact the delivery of a Facilities Study?

While a Facilities Study is associated with a specific project, the impact of all projects in the queue must be considered in determining the impact on the overall transmission system. As noted above, the Facilities Study will include stability analyses to identify additional upgrades that may not have been identified in the System Impact Study Report. Because PJM cannot consider individual projects in a vacuum when determining the need for network upgrades, PJM's stability analysis must ensure that the impact on the network of all discrete projects in the New Service Queue are considered. This necessary analysis can make it difficult to determine the exact time a Facilities Study will be issued. This complexity is further magnified by the increasing level of queue submissions before PJM as Transmission Owners seek to upgrade their systems and generation developers request connections of new facilities.

Q18. Is PJM actively addressing the increased demand for facilities studies?

Yes. On June 12, 2022, in Docket No. ER22-2110, PJM filed a request to revise its tariff addressing new interconnection service requests. These changes were approved, effective January 3, 2023, in an order issued on February 2, 2023.

V. GAO 2022-01

Q19. Are you familiar with GAO 2022-01?

Yes. The GAO provides guidelines for additional evidence to be provided in connection with petitions regarding electric generation under Ind. Code ch. 8-1-8.5 that request a CPCN for new electric generation and under Ind. Code ch. 8-1-8.8 that request approval of a multi-year PPA for electric generation.

Q20. Please provide the information requested by GAO 2022-01 as it applies to the Clean Energy Projects I&M is requesting approval of under Ind. Code ch. 8-1-8.5 or 8-1-8.8.

The required information as it pertains to this application is provided in Attachment BT-1 (for the CPCN projects) and Attachment BT-2 (for the PPA projects) to this testimony.

VI. Conclusion

Q21. Please summarize your conclusions and recommendations.

As I have explained above, the Clean Energy Projects are progressing through the PJM interconnection process. PJM is responsible for this process and as the RTO will make the final decisions regarding interconnection. The Company has also provided the information required by the recently adopted GAO-2022-01.

Q22. Does this conclude your pre-filed verified direct testimony?

Yes.

VERIFICATION

I, Bartley Taberner, Transmission Planning Manager at American Electric Power Service Corporation, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information, and belief.

Date: 3/23/23

Bartley Taberner

I&M Exhibit: ______

INDIANA MICHIGAN POWER COMPANY

CAUSE NO. 45868

PRE-FILED VERIFIED REBUTTAL TESTIMONY

OF

BARTLEY TABERNER

Content

REBUTTAL TESTIMONY OF BARTLEY TABERNER
ON BEHALF OF
INDIANA MICHIGAN POWER COMPANY

I. Introduction

Q1. Please state your name and business address.

My name is Bartley Taberner. My business address is 8600 Smiths Mill Road, New Albany, Ohio 43054.

Q2. By whom are you employed and what is your position?

I am employed by the American Electric Power Service Corporation (AEPSC) as a Transmission Planning Manager for East Transmission Planning in AEPSC's Grid Solutions group, (Grid Solutions). AEPSC is a shared services organization that allows American Electric Power (AEP) to achieve economies of scale and provide operational expertise and efficiencies in the provision of engineering, financing, accounting, planning, advisory, and other services to the subsidiaries of the AEP system, one of which is Indiana Michigan Power Company (I&M or the Company).

Q3. Are you the same Bartley Taberner who submitted pre-filed direct testimony in this case?

Yes.

II. Purpose of Rebuttal Testimony

Q4. What is the purpose of your rebuttal testimony?

The purpose of my testimony is to respond to the following matters raised in testimony filed by Mr. Gregory Krieger on behalf of the Indiana Office of Utility Consumer Counselor (OUCC):

- The OUCC position that the interconnection costs for purchase sale agreements (PSAs) are higher in comparison to the power purchase agreements (PPAs).
- The OUCC statement that interconnection costs related to PPAs and PSAs should be competitively bid.

Q5. If you do not respond to a particular issue or position addressed in an intervener's testimony, does that imply acceptance of his/her position over that proposed by I&M?

No, it does not.

III. Interconnection Costs

Q6. OUCC witness Krieger (p. 9) claims that the PJM cost estimates for PSAs are higher than the PJM interconnection costs for PPAs. Please respond.

The differences in interconnection costs for the facilities in this application are primarily due to the different connection voltages of the Clean Energy Project PSAs and PPAs. The Lake Trout and Mayapple Clean Energy PSA Projects both connect at 345kV, while the Sculpin and Elkhart Clean Energy PPA Projects are connecting at 138kV. An interconnection at 345kV is going to require larger, more expensive equipment and a larger footprint than facilities constructed at 138kV. Estimated interconnection costs are provided in the System Impact Study reports that were provided in my direct testimony in Table BT-1.

Table BT-1R below compiles the interconnection costs from the PJM Feasibility and Generation Interconnection Impact Studies Mr. Krieger relies on. As shown in Table 1, projects connecting at the same voltage level are shown to have comparable costs although each project is unique and cost estimates are specific to nature and location of each connection request.

Table BT-1R: Summary of Interconnection Cost by Connection Voltage

Project	**Mayapple**	**Lake Trout**	**Elkhart County**	**Sculpin**
Voltage	345kV	345kV	138kV	138kV
PJM Cost Estimate ($M)	$23.7	$23.8	$7.8	$9.7

Q7. How is the interconnection voltage level for each project determined?

This is dependent on the developer of the project. When the developer submits a New Service Request at PJM they will select a location generally based on the size of the generation facility being proposed, availability of land, and proximity to transmission facilities believed to have adequate capacity to accept the output of the proposed generation. The voltage level of those transmission facilities will determine the required voltage of the generation interconnection.

Q8. In Table BT-1R above, why do the PSA Projects have higher costs than the PPA Projects?

These higher costs are not a function of type of contract. As discussed above they are primarily a function of the interconnecting voltage level and can also be affected by the size of the proposed generating facilities. The Mayapple and Lake Trout Projects are not only connecting at a higher voltage but also have greater generating capacity than the Elkhart County and Sculpin Projects. Both factors lead to higher interconnection costs for the two PSA Projects over the two PPA Projects.

IV. Project Costs

Q9. OUCC witness Krieger (p. 12) asserts that interconnection costs are very difficult to estimate. Does the Company have previous experience with Independent Power Producer interconnection projects?

Yes. AEPSC has completed 56 interconnection projects since 2006. This includes 16 interconnection projects at the 138kV voltage and 17 interconnection projects at 345kV voltage. AEP has considerable experience in analyzing and facilitating interconnections to its system.

Q10. Please describe the current process used to estimate the PJM interconnection costs.

All projects are built in accordance with good engineering practices and the planning/operating standards and guidelines set forth by North American Electric Reliability Corporation (NERC), PJM, the Institute of Electrical and Electronics Engineers, Inc., the National Electrical Safety Code (NESC), the Occupational Safety and Health Administration (OSHA), and the American National Standards Institute (ANSI). A robust modeling process is used to prepare project estimates. Inputs to the modeling process include: historical results by project type; current labor and unit price cost contracts that are competitively bid; blanket contract costs for materials for the entire AEPSC system that take advantage of volume pricing; construction standards to reduce design costs and make these costs more predictable; stores oversight to marshal or stage materials by project and arrange for timely deliveries for materials to the job site to reduce and predict delivery material handling costs; and the inclusion and review of all overhead costs to ensure the final project estimates are reasonable and consistent.

Q11. OUCC witness Krieger (pp. 12-13) claims that interconnection costs should be competitively bid citing affordability concerns. Please respond.

OUCC witness Krieger's perception reflects a lack of understanding of the current processes being used for interconnection projects. As discussed below, the process used by the Company to develop transmission interconnections (as well as other projects) does utilize competitive bidding

Q12. Does the Company currently use a competitive bidding process for interconnection projects?

Yes, AEPSC requires all projects estimated at over one million dollars to go through the competitive bidding process. There can be circumstances where a project over this threshold would not be competitively bid, but such departures from these requirements would need to be individually vetted and approved by AEPSC Energy Delivery management.

Q13. Please explain how the competitive bidding processes keeps the cost of interconnection projects reasonable.

As projects move into the engineering and execution phases, a competitive bidding process is used to vet contractors that will perform transmission construction and in the procurement of the necessary equipment and materials. The competitive bidding process for contractors involves soliciting bids from a pre-qualified contractor, based on a bid package developed by AEPSC that includes the specifications, terms, and conditions for the contract. After receipt, bids are evaluated based on the contractor's safety record, price, capability, and availability and a contractor chosen. Similarly, AEPSC utilizes the competitive process to ensure that materials and equipment for a project will be sourced from the lowest cost vendor that can meet AEPSC's expectations for quality, deliverability, and safety. Contracts for the project will then be executed between AEPSC and the supplier. These processes ensure that AEPSC can leverage its economies of scale in contracting construction work, thus ensuring that projects will be built by qualified contactors at the lowest achievable cost.

AEPSC is the final approver of all contractor invoices and change orders after review by our Project Management organization. As the final approver, AEPSC has on-going transparency to project spending.

Q14. Is it your expectation that the interconnect projects associated with the Clean Energy Projects will use the competitive bidding process?

Yes, at this time I expect each of these projects to be competitively bid once they receive all approvals and move into the engineering and execution phases.

Q15. Please summarize your response to the OUCC witness Krieger's testimony in this case.

The differences in interconnection costs for the facilities in this proceeding are mainly due to the different connection voltages and the generating capacity of the PSAs and PPAs. The PSAs are both connecting at 345kV while the PPAs are connecting at 138kV. The commercial structure of the projects (PSA vs. PPA) do not have any bearing on the interconnection voltage or the associated interconnect costs. Interconnection costs are thoroughly analyzed and competitive bidding is appropriately used to assure market pricing and position. AEPSC leverages its economies of scale in contracting construction work, thus ensuring that projects will be built by qualified contactors at the lowest achievable cost.

Q16. Does this conclude your pre-filed verified rebuttal testimony?

Yes.

VERIFICATION

I, Bartley Taberner, Transmission Planning Manager at American Electric Power Service Corporation, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information, and belief.

Date: 5/30/23

Bartley Taberner

I&M Exhibit: _____

INDIANA MICHIGAN POWER COMPANY

CAUSE NO. 45868

PRE-FILED VERIFIED REBUTTAL TESTIMONY

OF

ANDREW J. WILLIAMSON

Content

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

I. Introduction

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 what is your position?

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

Q3. Are you the same Andrew J. Williamson who submitted pre-filed direct testimony in this case?

Yes.

II. Purpose of Rebuttal Testimony

Q4. What is the purpose of your rebuttal testimony?

The purpose of my testimony is to respond to the following matters raised in this case by Indiana Office of Utility Consumer Counselor (OUCC) witness Hanks and Citizen Action Coalition (CAC) witness Inskeep regarding affordability, OUCC witnesses Hanks and Latham and CAC witness Inskeep regarding PTC ratemaking treatment, and OUCC witness Blakley regarding accounting and ratemaking for the Clean Energy PSA and PPA Projects and CAC witness Inskeep regarding distributed generation and community solar.

Q5. If you do not respond to a particular issue or position addressed in an intervener's testimony, does that imply acceptance of his/her position over that proposed by I&M?

No, it does not.

III. Affordability

Q6. On page 3 of his testimony, OUCC witness Hanks states that I&M provided an average percentage increase for a residential customer but did not provide an average customer bill impact per 1,000 kWh. Please respond.

I&M provided an average percentage increase for residential, commercial and industrial customers because this information can be more easily applied across all customers than a stated dollar amount per some unit of usage. These rate estimates can be found in Attachment AJW-4, Attachment AJW-5 and 5C to my direct testimony. Attachment AJW-4 represents the estimated rate impact specific to the Clean Energy Projects alone and Attachment AJW-5 represents a the estimated rate impact considering a holistic view of I&M's generation transformation, including the cost of the Clean Energy Projects and the recent cost reductions associated with Rockport Unit 2 which is a substantial net reduction in costs for customers. The OUCC testimony focuses on the estimated rate impact specific to the Clean Energy Projects.

Q7. Can you provide an estimate of a bill impact for a residential customer with a 1,000 kWh usage in response to the OUCC's testimony?

Yes. I&M's annual residential kWh sales for 2022 was 4,331,863,885. Based on this kWh sales level an estimated bill impact for a residential customer with 1,000 kWh of usage would be an increase of approximately $3.00 based on the cost of the Clean Energy Projects, and a decrease of approximately $11.00 based on the net bill impact presented in Attachment AJW-5C which includes the recent cost reductions associated with Rockport Unit 2. These figures are based on the estimated annual residential revenue requirement and benefits divided by 4,331,863,885 kWh multiplied by 1,000 kWh.

Q8. Do you consider the estimated rate impact and bill impact to be aligned with the State of Indiana's objectives around affordability?

Yes. I&M, like the OUCC, is concerned about affordability for Hoosiers. Affordability was one of I&M's three main objectives of its 2021 IRP and underlies the steps that I&M has taken to acquire the resources needed to replace Rockport by the end of 2028. The rebuttal testimony of Company witnesses Lucas and Gaul further demonstrate how I&M's resource decisions and procurement practices have focused on affordability for I&M's customers.

Q9. On page 4 and 5 of his testimony, CAC witness Inskeep discusses how I&M's, and other Indiana investor owned utility's (IOUs), residential customer rates have changed since 2004. Please respond.

While I did not verify the details underlying the statistics and chart that Mr. Inskeep's includes in his testimony, I think it is important to note a few facts relative to his points. I&M acknowledges that its cost of providing service and rates has risen over the last nineteen years. I think it is fair to say this is also true about most of the costs we incur in our daily lives. What is important to understand about I&M, like other IOUs in Indiana, is we have an obligation to provide safe and reliable power to customers. This essential service comes at a cost. But what is unique about the cost of service that I&M provides when compared to many of the other costs we incur in our daily lives is that cost is subject to price regulation. Meaning, in order for our cost of service to change we must go through an extensive process to demonstrate that change is reasonable and necessary and ultimately receive Commission approval. What Mr. Inskeep's testimony highlights is the cost of providing electricity is increasing for all Hoosier utilities. Perhaps most importantly, when comparing I&M to other Indiana IOUs, I&M's rates have been on average among the most affordable. This does not discount the importance of affordability but it does underscore

I&M's commitment to support customer affordability. The rebuttal testimony of Company witness Lucas and Gaul further discuss how I&M's resource decisions and procurement practices have focused on affordability for I&M's customers.

Q10. Are there any other points you would like to make regarding the rate increases that have occurred over the last several years?

Yes. It is an incomplete assessment to just look at how rates have changed without considering why rates have changed and how those factors have enhanced the value of the service I&M provides customers in Indiana. Over this period, I&M has made significant investments that improve the value of service provided to customers, including:

- Lower environmental impacts of I&M's generation resources,
- Investments necessary to support an initial twenty (20) year extension of the Cook Nuclear Plant operating licenses which provides customers a significant amount of reliable capacity and stable, low cost and emission-free energy through 2034 and 2037,
- Improved the reliability and resiliency of I&M's distribution system through investments in aging infrastructure and grid modernization, and
- Improved the reliability, resiliency and capacity of the transmission system serving I&M's customers which also supports economic development opportunities for the state of Indiana and I&M's customers.

Q11. On page 6 of his testimony, CAC witness Inskeep states that "I&M threatens to disconnect Hoosier families from essential utility service." Do you agree with his characterization?

No I do not. I&M does not "threaten" its customers. I&M issues disconnect notices and disconnects service in compliance with the IURC rules.

Q12. On page 11 and 12 of his testimony, CAC witness Inskeep discusses cost allocation differences between the Fuel Cost Adjustment (FAC) and Solar

Power Rider (SPR) and recommends the Commission deny the Clean Energy PSA Projects on the basis of how the costs are allocated. Please respond.

This is not a valid basis for the Commission to assess the reasonableness and necessity of the Clean Energy Projects. The direct and rebuttal testimony of Company witness Gaul clearly explains the competitive procurement process that I&M undertook to acquire these resources and the differences amongst the resources that contribute to the differences in price. Ratemaking cost allocation is a highly debated topic that includes many considerations. I&M's proposal in this case was to simply continue the cost allocation methodologies or practices that have been approved by the Commission for current owned (i.e. PSA) and PPA resources. This results in solar PSA resources being allocated based on demand and solar PPA resources being allocated based on energy. This structure is reasonable and does not warrant the rejection of the proposed PSA Projects. The Commission should base its decision on the consistency with the 2021 IRP, the competitive procurement practices I&M used, the realities of the market, the need I&M has for capacity and the fact that I&M selected the projects which provided the most value for I&M's customers.

Q13. Do you have any other comments related to OUCC and CAC position regarding approval of the Clean Energy Resources and affordability?

Yes. I&M's objectives and goals underlying the resources proposed in this case are very well aligned with the goals and objectives of both the OUCC and CAC. The IRP objectives, resource procurement strategy and resource decisions have centered around affordability, sustainability, reliability, resource diversity, and resource adequacy for I&M's customers. Finally, it is important to reemphasize the information I provided in Attachment AJW-5C which highlights that the steps I&M has taken to date to transition its generation fleet, including the cost of the Clean Energy Resources, has resulted in a net cost savings for I&M and ultimately, our customers.

IV. Production Tax Credits (PTCs)

Q14. Please summarize OUCC witness Latham's and CAC witness Inskeep's recommendations with respect to the period over which PTCs should be reflected in I&M's cost of service.

Both the OUCC and CAC recommend I&M shorten this period to more closely match the ten (10) year period in which they are earned. The OUCC recommends a period of eleven (11) to twelve (12) years and the CAC recommends a period of ten (10) years.

Q15. What is the OUCC's basis for its recommendation?

The OUCC supports its recommendation stating that "ratepayers deserve the credit in a timely manner," that the twenty (20) year period proposed by I&M is "arbitrary," that cash flow does not appear to be an issue to I&M or AEP, and that "the PTC credit belongs to ratepayers and should be returned to ratepayers in an expeditious manner."[1]

Q16. What is the CACs basis for its recommendation?

The CAC supports its recommendation emphasizing concerns over affordability, higher immediate bill impact and it being in the best interest of residential customers to reflect the tax credits as quickly as possible.[2]

Q17. Do you agree that the twenty (20) year period proposed by I&M is arbitrary and that what is in the best interest of customers is to provide customers with the PTC benefits as quickly as possible?

No I do not. As discussed in my direct testimony and demonstrated in Figure AJW-3, I&M has proposed a twenty (20) year period as it provides much greater stability in cost of service for customers over the life of the PSA projects and

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[1] Public Ex. 3 (Latham) at 5.

[2] CAC Ex. 1 (Inskeep) at 14, 21.

also supports long-term customer affordability. Under the OUCC's and CAC's proposal, while I&M's initial cost of service may be lower, I&M's cost of service for the PSAs will increase dramatically when the PTC benefits end. As demonstrated by Figure AJW-3 in my direct testimony, this causes the annual revenue requirement associated with the Clean Energy PSA Projects to increase from approximately $63 million to approximately $102 million in year 11. This is dramatic and can be significantly mitigated if the Commission adopts I&M's proposal to reflect PTCs in its cost of service over a 20 year period. As discussed previously, customer affordability is also a focus of I&M's. However, the difference in the positions of the OUCC and CAC when compared to I&M appears to be a focus on affordability in the near-term versus affordability over the long-term. To say this another way, customer benefits and affordability shouldn't be viewed in terms of how we can maximize those today at the expense of customers tomorrow.

Q18. Do you agree with the OUCC suggestion that cash flow is not an important consideration for the Commission as well?[3]

No. The Commission should reasonably consider the cost of service implications cash flow has on I&M's customers. I&M is on the brink of a major generation transformation as we take the steps necessary to replace Rockport by the end of 2028. I&M's Preferred Portfolio in the 2021 IRP estimated it would require nearly $4 billion of incremental capital investment. This is nearly identical to I&M's total Indiana jurisdictional net plant reflected in its base rates approved by the Commission in Cause No. 45576. While it is true not all of these resources will be owned, PPAs still present significant long-term financial obligations for I&M much like debt and representative of the cost of the underlying resource. Cash flow is an important consideration to I&M's debt ratings underlying the cost of debt I&M incurs to operate its business. In addition, it is widely understood that financing costs are increasing, which is

[3] See Pub. Ex. 3 (Latham) at 5.

outside the control of I&M and the Commission. However, I&M's proposal to extend PTC benefits is within the control of the Commission. I&M's proposal in this case is to take advantage of this opportunity to support the long-term affordability and stability of I&M's cost of serving customers while at the same time increasing cash flow and reducing the risk that I&M's credit metrics will decline and result in higher cost of debt and therefore cost of service for I&M's customers.

Q19. Are there other beneficial factors related to I&M's proposal to extend the PTC benefits that are important for the Commission to consider relative to the OUCC's and CAC's recommendations?

Yes. As discussed on page 11 (Q21) of my direct testimony, I&M will record a regulatory liability to recognize the extension and deferral of the PTC benefits. This regulatory liability will be included in rate base and receive, to customers benefit, a pre-tax WACC return to recognize the time value of money associated with the deferred tax benefits. This reduces I&M's cost of service over the period of the deferral and would result in a levelized cost of energy that is not significantly different than if the PTCs were reflected in I&M's cost of service as recommended by the OUCC and CAC. The biggest difference is that I&M's proposal extends the benefits customers realize twice as long as the recommendations of the OUCC and CAC, providing greater stability for customers and supporting long-term affordability.

Q20. Do you agree with OUCC witness Latham (p. 5) that the "PTC credit belongs to ratepayers"?

No. Ratemaking is not a question of what belongs to customers vs the utility. I&M provides retail electric utility service, the price of which is necessarily underpinned by the cost of providing it, and subject to Commission regulation. I&M charges rates for electric service that are representative of the costs it incurs to provide that service, but it is rarely if ever a one-for-one reflection of the costs it incurs to provide that service. It is well understood that payment of electric service rates does not create any customer ownership rights to the underlying utility assets. That being said, the Company does not propose to "keep" the PTC benefit. The contested issue concerns the period of which the PTC should be flowed through rates. I explain above, why the Company's proposal should be approved.

Q21. Does OUCC witness Hanks address PTCs in his testimony?

Yes, but only related to his recommendations on page 17 and 18 of his testimony which summarize the positions taken by OUCC witness Latham.

Q22. Does any other I&M witness address PTCs in their rebuttal testimony?

Yes. Please see the rebuttal testimony of Company witness Hodgson.

V. Accounting and Ratemaking Related to Rate Base and Asset Retirement Obligations (AROs)

Q23. OUCC witness Blakley's testimony (at 4) expresses the term "average monthly rate base" is confusing. Please clarify I&M's request in this case.

On page 13 of my direct testimony, Q24, I explain I&M's request for authority to defer costs associated with the Clean Energy PSA Projects prior to inclusion in I&M's rates. A component of this deferral accounting request includes pre-tax carrying costs on the assets and liabilities (i.e. "rate base") I&M is requesting ratemaking treatment for the costs associated with the Clean Energy PSA Projects.

On page 13, lines 19-22, I explain the pre-tax carrying costs would be calculated based on the "average monthly rate base" including, 1) net plant in-service and 2) any deferred tax asset(s) and liability(ies) related to production tax credits (PTCs). Deferral of pre-tax carrying costs on rate base prior to inclusion in rates is consistent with the previous ratemaking treatment approved by the Commission.[4]

Q24. OUCC witness Blakley testimony (at 5) states that "At the time the deferred asset is included in rates for recovery, then the income tax gross up should be applied." Please respond.

I believe what Mr. Blakley is explaining is that the income tax expense is not incurred until the equity earnings are recognized for accounting purposes. This is correct and consistent with I&M's accounting for deferred carrying costs. The purpose of my direct testimony on this matter was to request that I&M be permitted to defer for later recovery carrying costs on rate base prior to inclusion in rates, including a tax gross-up on the equity return. This deferral authority supports timely recovery, as provided for by Indiana statute, of the costs I&M incurs related to the Clean Energy Projects before such costs are reflected in I&M's rates. This deferred balance would be recoverable in the future when I&M implements new SPR rates to reflect the Clean Energy PSA Projects.

Q25. Please explain how deferred carrying costs are accounted for.

Each month I&M will determine what the pre-tax carrying costs are on rate base and record the debt component as a regulatory asset and record the equity and tax components as a separate regulatory asset that has an equal and offsetting contra asset balance that nets to zero on I&M's balance sheet. This allows I&M to accurately track the full pre-tax carrying costs that will be recoverable in the future when the deferred costs are reflected in I&M's rates. Once the deferred pre-tax carrying costs are reflected in rates, the regulatory asset and contra asset related to the equity and tax components are reduced to reflect the pre-tax equity earnings[5]. As mentioned previously, I&M's request for deferral

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[4] The IURC approved deferral accounting and ratemaking treatment of pre-tax carrying costs in Cause Nos. 44511 (Clean Energy Solar Pilot Project) and 45245 (South Bend Solar Project) which related to owned solar investments that I&M was approved rider recovery of.

[5] In accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 980-340-25-5, the equity portion of the WACC based carrying charges (including a tax gross-up)

accounting treatment related to carrying costs on rate base is consistent with the ratemaking authority previously authorized for by the Commission.

Q26. OUCC Witness Blakley (p. 4) expresses concerns over I&M's use of the term "rate base." Are the types of costs I&M identified to be included in rate base related to the Clean Energy PSA Projects commonly included in rate base in Indiana?

Yes they are. Indiana commonly includes net plant in-service, inventory balances, materials and supplies, regulatory assets and liabilities, certain tax-related balances and certain prepayments in rate base for purposes of determining base rates and rider rates. These costs are incurred during the construction and operation of the Clean Energy Projects.

Q27. OUCC Witness Blakley (p. 4) states that "All capital investment trackers recover the direct incurred costs of the capital investment and should not include any other rate base items such as material and supplies or working capital." Please respond.

First, it is important to point out that in this proceeding I&M has not proposed ratemaking treatment for materials and supplies or working capital related to the Clean Energy PSA Projects. However, I do not agree that materials and supplies is not recoverable in investment trackers. Materials and supplies can be a direct cost incurred during construction or operation of a project. In fact, the Commission has previously approved inclusion of consumable (also known as reagent, such as sodium bicarbonate used to control SO_2 emissions) inventory balances in rate base for trackers that recover environmental controls equipment costs.[6]

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on electric plant in service or a regulatory asset balance can be recognized as income only when it is included in rates and billed to customers.

[6] Cause Nos. 44331 (Rockport DSI) and 44523 (Rockport Unit 1 SCR)

Q28. Does the fact that I&M is requesting to track these costs through a deferral or rider mechanism change the reasonableness of I&M's proposal?

No. The purpose of the deferral and rider request is to provide timely recovery of the costs incurred by I&M related to the Clean Energy PSA Projects that would typically receive ratemaking treatment, whether in base rates or in a rider. It is also consistent with the statutory framework in Indiana which provides incentives for clean energy projects (8-1-8.8-11) and recovery of costs through rate adjustment mechanisms (8-1-8.8-12).

Q29. You clarified the Company's proposal above in response to OUCC witness Blakley's misunderstanding regarding the term "average monthly rate base". Why does I&M propose using "average" monthly rate base?

Each month, activity occurs that changes the value of the rate base. For example, each month can reflect additions to plant in-service and associated depreciation. Other balances included in rate base can change from month to month as well. Since a rider or deferral mechanisms are established to track recoverable costs and/or credits on a monthly basis, it is necessary to pick a point in time each month for valuation of rate base to determine a carrying cost for that period. Generally speaking, there are three main options, beginning of month, end of month or an average. The Commission has commonly approved use of an average rate base for I&M to calculate carrying charges.[7] This approach accounts for the activity that occurs during the course of a month that changes rate base and reasonably reflects that activity in the determination of carrying charges. I&M's proposal in this case is simply to follow what the Commission has commonly approved in past cases.

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[7] Cause Nos. 44182 (Cook LCM), 44331 (Rockport DSI), 44523 (Rockport Unit 1 SCR), 44871 (Rockport Unit 2 SCR), 44511 (Clean Energy Solar Pilot Project) and 45245 (South Bend Solar Project).

Q30.

Q31. Please summarize OUCC witness Blakley's testimony regarding Asset Retirement Obligations (AROs).

Mr. Blakley generally addresses what an ARO is on page 3, lines 15-22 and page 4, lines 1-2. In addition, on pages 5-8 Mr. Blakley has several Q&As discussing this topic. He concludes (inaccurately as I explain below) that ARO costs are or should be included in I&M's proposed depreciation rates. Ultimately, on page 9 of his testimony (lines 7-20), Mr. Blakley recommends that I&M should not include any forecasted or estimated non-cash expensed ARO balances that reside on I&Ms balance sheet in its SPR tracker. He testifies that they are not included in base rates as a return on investment nor a recovery of expenses and therefore should not be included in the SPR. Mr. Blakley states that that I&M should update its depreciation rates including estimates for ARO decommissioning costs net of salvage in later depreciation studies following in-service dates of the new solar resources. He adds that the proper ratemaking treatment for ARO decommissioning cost estimates is that they be included in I&M depreciation rates and net salvage calculations along with all the other existing asset decommissioning costs, and at the time of retirement of the assets, the actual removal costs incurred be charged to accumulated depreciation.

Q32. Do you agree with Mr. Blakley's recommendation related to AROs?

I agree that I&M should not recover a return on the ARO non-cash asset *balances* and clarify that I&M has not requested to do so. I disagree with Mr.

Blakley's recommendation regarding ARO ***expense***. I&M is only requesting recovery of the ARO ***expenses*** that I&M incurs related to the Clean Energy PSA Projects. As I describe in my direct testimony, page 8 lines 14-17, ARO expense is comprised of depreciation of the non-cash ARO asset and accretion of the ARO liability. The sum of ARO depreciation and accretion expenses represent I&M's annual cost of service impact. For accounting purposes, the initial non-cash ARO asset and liability are equal to one another. Over the life of the asset, the non-cash ARO asset is depreciated to zero and the ARO liability is accreted to its future or final value. Recognizing both the non-cash ARO asset depreciation expense and the ARO liability accretion expense in cost of service over the life of an asset allows this cost to be reflected in rates while the asset is used and useful in the provision of service to customers. This is consistent with the ratemaking for AROs associated with current assets and current base rates approved by the Commission in Cause No. 45576.[8]

Q33. Did I&M include ARO costs in its proposed deprecation rates for the Clean Energy PSA Projects?

No. I&M's proposed depreciation rates only include the estimated salvage value of the facilities. My direct testimony (QA14) states: "Specifically, I&M is requesting Commission approval to calculate depreciation rates for each project based on a 35-year expected useful life and the initial net salvage estimates." I explained that the current estimates for net salvage indicate positive net salvage for each PSA project. *Id.* I provided the current estimates in my Attachment AJW-1 (and the supporting confidential workpaper). I also explained how the salvage value estimates were developed for each project. My explanation referred to a study discussed and included in Company witness Lozier's testimony as Attachment BEL-5C. *Id.* at (QA15). That study estimated salvage value by resource type which was then used to calculate a salvage value

[8] Attachment JCD-1 (Test Year Jurisdictional Separation Study) and Workpaper WP IM JCOS-CCOS TYE 12_31_22_End of Period Settlement.

estimate based on the specifics of each project. *Id.* I explained that the initial estimate of salvage value for each project is reasonable and going forward, salvage value will be reviewed and updated in later depreciation studies following the in-service dates of the new resources. To summarize this testimony, I&M only included an estimate of salvage value in its proposed depreciation rates and requested separate ratemaking treatment of ARO costs for the Clean Energy PSA Projects.

Q34. What is the difference between the ARO costs mentioned in your direct testimony and the net salvage included in the Company's depreciation rate request?

The study included as Attachment BEL-5C is a decommissioning analysis for the dismantling, removal, and salvage (or disposal) of equipment and materials that make up a generic solar PV power plant. The consultant, DNV, prepared cost estimates based on the labor costs to disassemble and demolish, remove and salvage (or dispose) of project equipment and material, and included consideration of the scrap value. The analysis and cost estimates are based on publicly available industry cost information and DNV's database of experience in the electric power industry. The resulting cost estimates for a generic solar PV power plant were then used to determine the estimated cost per MWdc for solar. The decommissioning cost for each of proposed Clean Energy PSA Project was calculated by scaling the project size by this estimate cost, which is typical for decommissioning cost estimates in the electric power industry.

I believe there may be confusion due to the difference between how "decommissioning" costs are treated for renewable generation assets and fossil generation assets. In my direct testimony, I explained (QA 17) that each Clean Energy PSA Project is constructed on land that is leased and I&M, as owner of the asset, has an obligation to remove the associated equipment and return the land to certain conditions after each project is retired. The estimated cost of this "decommissioning" is accounted for as an ARO expense, according to GAAP, and is necessary to recognize in I&M's ratemaking. My ratemaking discussion focused on "ARO expense." As discussed earlier, ARO expense is comprised of depreciation of the non-cash ARO asset and accretion of the ARO liability. The sum of ARO depreciation and accretion expenses represent I&M's annual cost of service impact.

The Company proposes that as I&M makes future SPR filings, I&M will include the forecasted ARO expenses (ARO accretion expense and ARO depreciation expense) in its SPR revenue requirement and reconcile to actual ARO expenses for past periods. I&M is requesting to utilize the initial estimates presented in this case for ratemaking until such time as ARO estimates are updated in the future.

Q35. Beginning on page 6 line 20 through page 8 line 14 OUCC witness Blakley addresses ratemaking for AROs and depreciation of plant investments. Does his testimony accurately reflect I&M's proposal on these matters?

No, as mentioned above, I believe the term "decommissioning" may have led to confusion regarding I&M's request and this in turn impacted the resulting OUCC recommendations. ARO costs are separate and distinct from the other costs of closing a fossil generation resource that are typically included in the net salvage component of depreciation rates approved in Indiana. I explain this on page 8 (Q17) of my direct testimony.

In discovery, the OUCC asked whether the ARO costs mentioned in my direct testimony represent the estimated net decommissioning costs shown in the study of estimated net salvage of solar projects included with Company witness Lozier's testimony.[9] The Company's DR response stated that the ARO costs mentioned in my direct testimony are *not* the same and are not combined with the estimated net salvage shown in the study included with witness Lozier's testimony. [10]

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[9] A copy of this DR is included with Mr. Blakley's testimony as OUCC Attachment WRB-1. The term "net salvage" refers to the cost of removal less salvage, which for the Clean Energy PSA Projects "net salvage" only includes a salvage credit.

[10] *Id.*

Q36. Is OUCC witness Blakley correct that the ARO asset(s) and liability(ies) represent estimated non-cash future expenditures?

Yes. However, that does not change the reasonableness and necessity to reflect the period *expense* related to these balances in I&M's cost of service over the life of the associated assets. If that was not done, as Mr. Blakley suggests, it would result in fully recognizing the cost of the AROs (which can be significant) in customer rates after the related asset is retired and no longer used and useful in the provision of service to customers. This ratemaking treatment is no different than the non-ARO closure costs and salvage credits that are not incurred or realized until after an asset is retired but are recognized in depreciation rates and cost of service over the life of the associated asset.

Q37. Please address CAC witness Inskeep's testimony (p. 13, 21) related to distributed generation and community solar and his recommendation that the Commission direct I&M to create new tariffs.

I&M agrees with Mr. Inskeep that distributed generation and community solar are relevant considerations for an IRP and welcomes and encourages the CAC's participation and feedback during I&M's next IRP process. I disagree with his suggestion that the statutory methodology for setting compensation for Excess Distributed Generation tariffs is unfair. That being said, these matters, including the creation of new tariffs related to distributed generation and community solar, are outside the scope of this proceeding which is focused on I&M's need to replace the 2,600 MW Rockport plant by the time it retires in 2028. As a practical matter, new tariffs related to distributed generation and community solar would not meaningfully change the need for new capacity to replace Rockport and does not warrant denying approval of the Mayapple and Lake Trout Clean Energy PSA Projects.

Q38. Does I&M currently have a distributed generation tariff available to its customers?

Yes. I&M's current Excess Distributed Generation Rider compensates customers at a rate of approximately $85/MWh[11] which is [redacted] of Clean Energy Projects, which includes the Mayapple and Lake Trout PSA Projects the CAC claims are too costly for customers. It is important to also point out that distributed generation resources do not provide I&M with PJM-accredited capacity or renewable energy certificates (RECs) like the Mayapple and Lake Trout PSA Projects will. Lastly, as discussed on page 21 my direct testimony, the RECs produced by the Clean Energy Projects will produce additional revenues that will effectively reduce the LCOEs for each of the Clean Energy Projects.[12]

VI. Summary

Q39. Please summarize your testimony.

The Clean Energy Projects and I&M's corresponding accounting and ratemaking proposals support affordability for I&M's customers while allowing I&M to transition its generation fleet in a way that supports sustainability, reliability, resource diversity and resource adequacy for I&M's customers. Likewise, I&M's proposal to extend PTC benefits supports long-term customer affordability and improve cash flow thereby reducing the risk of declining credit metrics and increasing cost of debt financing and should be approved. I&M's proposed accounting and ratemaking treatment for rate base and AROs related to the

[11] See Indiana Michigan Power Company tariff book, Rider EDG, First Revised Sheet No. 41.8 "Procured Generation Credit". https://www.indianamichiganpower.com/lib/docs/ratesandtariffs/Indiana/IMINTB19_05-01-2023_updated.pdf

[12] The average sales price of RECs for 2022 was approximately $23/REC and for 2023 has been approximately $30/REC.

Clean Energy PSA Projects is reasonable and consistent with the ratemaking treatment that has been previously approved by the Commission and is currently reflected in I&M's rates. The CAC's recommendations to create new tariffs related to distributed generation and community solar are outside the scope of this case, would not change I&M's need for the Lake Trout and Mayapple PSA Projects, and fail to recognize today I&M pays customers for excess distributed generation at a higher cost than the blended cost of the portfolio of Clean Energy Projects. In conclusion, the Commission should approve all four (4) Clean Energy Projects along with the ratemaking and accounting requests discussed in my direct testimony.

Q40. Does this conclude your pre-filed verified rebuttal 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: May 31, 2023

Andrew J. Williamson

Andrew J. Williamson