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I&M Exhibit: _____

INDIANA MICHIGAN POWER COMPANY

PRE-FILED VERIFIED DIRECT TESTIMONY

OF

SHELLI A. SLOAN

Cause No. 45933

Content

DIRECT TESTIMONY OF SHELLI A. SLOAN
ON BEHALF OF
INDIANA MICHIGAN POWER COMPANY

I. Introduction of Witness

Q1. Please state your name and business address.

My name is Shelli A. Sloan 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) as Director Financial Support and Special Projects in Corporate Planning and Budgeting (CP&B). AEPSC supplies engineering, accounting, planning, advisory, and other services to the subsidiaries of the American Electric Power (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 earned a Bachelor of Science in Business Administration Degree from The Ohio State University in 1991 and a Master of Business Administration from Ashland University in 2002. I was hired by AEPSC in 1998 into the Information Technology (IT) organization where I performed multiple roles in the Resource Management group and the Project Management Office. In 2009 I joined Regulatory Services as a Regulatory Consultant supporting fuel filings for all AEP operating companies.

From 2012 through 2017, I was a Regulatory Case Manager, overseeing large and complex regulatory filings for multiple AEP operating companies. In 2018, I was promoted to the position of Director Case Support and Special Projects where I led a team responsible for Integrated Resource Plan filings, Renewable acquisition filings, and witness support in all AEP jurisdictions. I moved into my current role in 2021.

Q4. What are your responsibilities as Director Financial Support and Special Projects?

As Director of Financial Support and Special projects, I am responsible for directing the support of certain regulatory activities within the forecasting group, overseeing and compiling the preparation of earnings materials and projections, managing the overall flow of the financial forecast process, and leading various special projects involving the Finance organization. I assist in the preparation of financial forecasts in conjunction with operating company personnel, variance analyses, regulatory filings, and other ad hoc analysis for the AEP Operating Companies. In this role, I assist in the preparation and review of short- and long-term forecasts for I&M.

Q5. Have you previously testified before any regulatory commissions?

Yes, on behalf of I&M, I have filed direct testimony before the Indiana Utility Regulatory Commission in Cause No. 45576, base rate case, and Cause No. 38702 FAC 87 – 91. I have also provided testimony before the Michigan Public Service Commission on behalf of I&M in power supply cost recovery proceedings. In addition, I have testified and/or submitted testimony before the Public Service Commission of West Virginia on behalf of Appalachian Power Company (APCO) and Wheeling Power Company and before the Virginia State Corporation Commission on behalf of APCO in fuel factor proceedings.

II. Purpose of Testimony

Q6. What is the purpose of your testimony?

My testimony presents I&M's Total Company 2024 Test Year financial forecast, which is unadjusted, and discuss the forecast process. I also support the Fuel Adjustment Clause (FAC) basing point. In addition, I sponsor Rate Base Adjustment No. 8 to correct an error in forecasted fuel stock.

The financial forecast I present is necessarily informed by a number of subject matter experts that are also being presented by the Company, and who provide any necessary adjustments to the forecast.

Q7. Are you sponsoring or co-sponsoring any exhibits?

Yes, I am sponsoring the following exhibits:

- I&M Exhibit A-2 – Balance Sheet
- I&M Exhibit A-3 – Statement of Cash Flows
- I&M Exhibit A-4 – Income Statement

Q8. Are you sponsoring any attachments?

Yes, I am sponsoring the following attachments:

- Attachment SAS-1 – Operating Income Comparison
- Attachment SAS-2 – Revenue Comparison
- Attachment SAS-3 – Historical and Forecasted O&M Expenses
- Attachment SAS-4 – Historical and Forecasted Capital Expenditures
- Attachment SAS-5 – Fuel, Consumables, Allowances and Purchased Power Expenses
- Attachment SAS-6 – Transmission Revenues and Expenses

- Attachment SAS-7 – Historical Functional Plant Activity
- Attachment SAS-8 – I&M Plant Summary
- Attachment SAS-9 – UI Model Overview
- Attachment SAS-10 – Fuel Adjustment Clause (FAC) Basing Point

Q9. Are you sponsoring any workpapers?

Yes, I am sponsoring the following workpapers:

- WP SAS-1 Retail and FERC Sales Detail
- WP SAS-2 Off-System Sales Detail
- WP SAS-3 Transmission and Other Electric Revenue Detail
- WP SAS-4 Purchased Power Detail
- WP SAS-5 Net Plant Balance Sheet
- WP SAS-6 Testimony Figures
- WP SAS-7 Net Energy Cost
- WP SAS-8 Nuclear Fuel Summary
- WP SAS-9 Project Life File (Capital Forecast by Project)
- WP SAS-10 O&M

Q10. Were the exhibits, attachments, and workpapers that you sponsor prepared by you or under your direction and supervision?

Yes, the exhibits, attachments, and workpapers including forecasted Test Year information were prepared by me or under my direction and supervision. Historical period values, while included in my testimony, exhibits, attachments, and workpapers for presentation purposes, were prepared from Company business records at my request by or under the direction and supervision of

Company witnesses Ross and Cash. I have found the work prepared by these witnesses to be reliable.

Q11. Please summarize your testimony.

I&M's Test Year financial forecast is the result of a thorough forecasting process which supports each element presented in the jurisdictional separation study. A forecast takes the assumptions developed from the Company's management experience, knowledge and judgment and uses those to develop the work plans that become the basis for I&M's forecast. The operations and maintenance (O&M) and capital forecasts prepared by each business unit are based on work plans that use business objectives to prioritize work activities. In addition to the functional business unit forecasts, I&M also incorporates the capital and O&M budgets and long-range forecasts from AEPSC for corporate services including, but not limited to, IT and shared services. I&M management works across the business units to evaluate the drivers behind the components of the work plan to ensure capital and O&M are prioritized, allocated properly, and are within available capital and O&M guardrails. The forecast accurately reflects the data and inputs provided at the time it was developed, is reasonable, and is representative of I&M's going forward cost of providing service. The forecasting process used in this proceeding is the same that was used in I&M's two most recent basic rate cases, Cause Nos. 44576 and 45235.

I&M uses a financial modeling program designed specifically for investor-owned utilities by Utilities International (UI) to prepare the Total Company, integrated financial forecast. This model integrates I&M's work plans with a number of other forecast inputs to generate a financial forecast.

The FAC basing point for the Test Year is 12.981 mills per kWh, as shown on Attachment SAS-10.

III. I&M's Forecasting Process

Q12. Please describe the forecasting process used to develop I&M's financial forecast.

The forecasting process used in this proceeding is the same that was used in I&M's two most recent basic rate cases, Cause Nos. 44576 and 45235. I&M's financial management team and CP&B work collaboratively throughout the process to prepare I&M's financial forecast.

I&M, CP&B, and other corporate groups involved in developing the forecast utilize the best information and data available at the time the forecast is prepared to incorporate the latest underlying assumptions. The established assumptions include items such as kilowatt-hour sales, fuel expense, interest rates, and cost projections based on each of I&M's business unit work plans.

The final result of the forecasting process is what is referred to as I&M's Budget and Long-Range Plan. The Budget represents the forecast for the next calendar year, and the Long-Range Plan represents the forecast for subsequent periods. The Budget and Long-Range Plan are collectively referred to as the financial forecast. The completion of the forecast also produces forward-looking financial statements similar to financial statements based on actual results.

Q13. Please describe the financial model used in the forecasting process.

As explained above, I&M utilizes a financial modeling program designed specifically for investor-owned utilities to prepare the Total Company, integrated financial forecast. This model integrates I&M's work plans with a number of other forecast inputs to generate a financial forecast.

The model contains a number of algorithms that apply assumptions and logic to the forecast inputs and generate forward looking financial statements and ratios. Please refer to Attachment SAS-9 for an overview of the UI financial model.

Q14. What forward-looking Test Year has I&M proposed for setting rates in this proceeding?

I&M has proposed rates based on a forward-looking calendar year Test Year of January 1, 2024 through December 31, 2024. For capital projects, the Company has used a Capital Forecast Period of January 1, 2023 through December 31, 2024.

Q15. What period has I&M used as a Historical Period?

For a Historical Period, I&M used the most recent calendar year for which audited financial statements were available at the time of this filing, which is the 2022 calendar year.

Q16. Please discuss the timeline for establishing the financial forecast utilized in this proceeding.

Each year CP&B establishes the timeline for preparing the annual financial forecast. The 2022 annual process, which establishes the budget for 2023 and the Long-Range Plan for 2024 – 2030, started in February 2022 with identifying assumptions and preparing initial elements of the forecast.

Through May of 2022, each of I&M's business units established and incorporated their work plans into the proposed forecast. During June 2022, CP&B coordinated inputs from various corporate groups and performed the modeling process for the initial financial forecast. I&M's management team participated in reviews of the major components throughout the process.

During July 2022, I&M worked with CP&B to finalize the proposed financial forecast. I&M presented this proposed 2023 budget and 2024-2030 Long Range Plan to the AEP Investment Review Committee (IRC) in early August of 2022. Updates to the financial forecast continued through September with a lockdown for 2023 budgeting purposes taking place in late September 2022. The Company used this forecast and incorporated select and targeted updates through February 2023 to prepare the financial forecast presented in this proceeding for the Test Year and Capital Forecast Period.

Q17. How were I&M's forecasted income statement and balance sheet developed?

The forecasted income statement as shown on I&M Exhibit A-4 and balance sheet as shown on I&M Exhibit A-2 were prepared in accordance with AEP's normal forecasting processes. They are based on the consolidation of data provided by business units and various corporate departments. The forecast is fully integrated between the income statement, balance sheet, and cash flows.

Q18. Does I&M's forecasted balance sheet fairly and reasonably reflect the account balances expected for the Company during the Test Year?

Yes. The forecasted balance sheet is based on the capital expenditures, operating costs, and capital structure reasonably necessary for the going forward operation of the utility. The forecasted balance sheet contains the components of rate base as shown on I&M Exhibit A-6 – Rate Base Summary.

Q19. How was I&M's forecasted statement of cash flows developed?

The forecasted statement of cash flows as shown on I&M Exhibit A-3 is a function of the items reflected in the forecasted balance sheet. Cash needs dictate the extent of debt and equity that is necessary to operate the business, given the timing of cash inflows and outflows.

Q20. Please discuss the major components of I&M's financial forecast used for the Test Year.

The major components of I&M's financial forecast used for the Test Year are supported by various witnesses as indicated below. CP&B receives the input and executes the financial forecasting process as demonstrated in Attachment SAS-9. I&M's financial forecast contains the following major components:

1) *Load and Demand Forecast* – I&M's load projection, sponsored by Company witness White, reflects an analysis of the economy and the unique factors that influence individual customers or customer classes in I&M's Indiana jurisdiction.

2) *Retail and Wholesale Federal Energy Regulatory Commission (FERC) Revenue Projections* – Company witness Fischer presents the Indiana retail revenues by tariff class utilizing current rates, including riders and the FAC. Revenues for large wholesale customers are developed in detail in accordance with the terms of the contract, including demand, energy, and fuel adjustment charges.

3) *Off-System Sales (OSS) Forecast* – The OSS (also referred to as non-firm sales) projections are developed by the Production Costing Department. The OSS Forecast includes both the cost to serve the sale and the resulting margins. Company witness Gruca discusses the ratemaking treatment of OSS margins.

4) *Generation Forecast* – I&M's generation forecast is also developed by the Production Costing Department. I&M's forecasted generation, together with planned energy purchases, is sufficient to meet the system's anticipated total energy requirements. This is the same forecasting methodology used in the Company's semi-annual FAC filings. The cost of fuel consumed is based on the generation forecast for each of the generating units in the AEP System. In addition to fuel costs, I&M incurs other variable costs of production, such as consumable materials, at our generating stations for the operation of environmental equipment, emission allowances, and purchased power costs.

5) *O&M Forecast* – O&M expenses, excluding energy costs, are based upon work plans for each of I&M's business units. These plans include expenditures for scheduled maintenance programs, as well as the cost of

operations. These plans take into consideration staffing levels, including budgeted increases in compensation as well as material costs necessary to perform each planned program.

6) *Construction Expenditure Forecast* – The various engineering and planning groups supporting each of I&M's business units develop the construction expenditure budget. That budget reflects expenditures and in-service dates of major projects as well as amounts approved to fund blanket work (smaller projects grouped together), which is essential in estimating depreciation as well as the allowance for funds used during construction (AFUDC).

IV. O&M and Capital Forecasts

Q21. Can you describe how the O&M and capital components of the financial forecasts are developed?

I&M's financial management team coordinates the planned activities necessary to complete the forecasting process with AEP's CP&B group. I&M and CP&B work collaboratively at the start of the forecasting process to establish capital and O&M guardrails for each business unit to utilize as a planning basis when preparing their work plans and forecasts.

The O&M and capital forecasts prepared by each business unit are based on work plans that use business objectives to prioritize work activities. In addition to the functional business unit forecasts, I&M also incorporates the capital and O&M budgets and long-range forecasts from AEPSC for corporate services including, but not limited to, IT and shared services.

Q22. Who are the Company witnesses supporting the O&M and capital expenditure work plan activities for the financial forecast?

The following individuals provide testimony supporting the O&M and capital expenditure work plan activities and associated expenditures for the financial forecast:

- Robert Jessee – Fossil, Hydro & Solar Generation
- Kelly Ferneau – Nuclear Generation
- David Isaacson – Distribution
- Nicholas Koehler – Transmission
- P. Joseph Brenner - Information Technology

Q23. Please describe how capital is prioritized and allocated across I&M's business units.

I&M's business units go through an effort to identify a work plan consisting of a list of prioritized capital projects for the future. Each business unit uses drivers specific to its area of the business to determine which projects to include and the timing by which the projects need to be completed.

Some examples of common business drivers include reliability improvements, environmental compliance, regulatory compliance (*e.g.*, Nuclear Regulatory Commission), PJM compliance, public/employee safety, aging infrastructure, and performance improvements.

Once each business unit determines its work plan and associated business unit drivers, the business unit is required to estimate the costs and schedule durations associated with each individual program or project. A necessary step that occurs during each business unit review is determining the level of capital that is associated with environmental, regulatory, risk mitigation or operational requirements, and the amount of capital available for remaining projects.

After the highest priority capital projects are approved, I&M's business unit leaders work collaboratively to prioritize remaining projects within I&M's overall capital limitations.

Q24. Please describe how O&M is prioritized and allocated across I&M's business units.

Each business unit develops its O&M budget based on the costs necessary to maintain ongoing operations plus incremental O&M needs. Ongoing operations costs typically include items such as labor, fringe benefits, fleet vehicles, insurance, consumable materials and chemicals, right of way maintenance, mandated fees, and other items necessary for the business unit to manage its core operations.

Each budget is prepared in accordance with Corporate Budgeting Guidelines, as provided in MSFR 1-5-7(7), which include various assumptions and provide guidance for things such as labor escalation factors. Inflationary factors that are impacting the general economy, as discussed by Company witness White, are also impacting I&M. In developing their work plans, business units are expected to account for inflationary factors and identify any potential financial pressures that may require additional discussions or funding to manage ongoing operations. Incremental O&M includes the cost associated with scheduled outages at major generating facilities and major inspection or maintenance programs within distribution and transmission.

Once ongoing operations O&M has been approved, proposed business unit incremental needs are evaluated and prioritized by I&M business unit leaders in order of greatest operational and/or customer benefit.

Q25. Please describe how capital and O&M outside the business units are prioritized and allocated.

AEPSC departments responsible for items such as IT and shared services are required to prepare strategic plans and financial forecasts that are presented to the AEP IRC to obtain approval for capital and O&M allocations. I&M reviews this information and provides input based on the specific impact and benefits to I&M.

Q26. How does I&M manage changes to the plans represented by the forecast?

I&M has multiple processes that are used in the ongoing management of capital and O&M throughout the year. I&M updates budgets annually and makes changes based on the updated needs of the business.

I&M also works with each business unit throughout the year to re-forecast capital and O&M expenditures and manage changes to the budget.

These processes provide platforms for open communications among the business units, I&M, and CP&B to ensure funds are prioritized and allocated effectively throughout the year.

Q27. Why are the changes to plans represented by the forecast reasonable and necessary in between forecast cycles?

Changes to the plans are reasonable and necessary to address new facts and circumstances that were not known at the time the plan was finalized to establish the forecast. These changes occur as a result of many emerging business needs, including changes in timing and scope of existing projects, new operational needs, new customer needs, supply chain constraints, weather events and new regulatory compliance requirements.

V. Operations and Maintenance Expense

Q28. Please discuss the O&M expenses included in the Test Year.

The O&M expenses, excluding energy costs, are based upon work plans for each of I&M's business units. Attachment SAS-3 provides a summary of actual O&M expenses for the years 2018 through 2022 and of the forecasted expenses for the Test Year. All numbers in this attachment are Total Company O&M expenses. This Attachment also shows the projected growth in O&M by account grouping.

The comparisons included in Attachment SAS-3 are dollar-for-dollar comparisons without adjusting for inflation over the five-year period. An inflationary adjustment to historical costs would be necessary to correctly reflect that cost during the Test Year.

Company witnesses Jessee, Ferneau, Isaacson, Koehler, and Brenner provide further support for the projected level of O&M expenses included in the Test Year.

Q29. Please provide a high-level summary of the Test Year O&M forecast.

As demonstrated in Attachment SAS-3, and provided in *Figure SAS-1* below, with the exception of Transmission, specifically PJM related costs, and Steam Generation, the forecasted O&M represents a modest increase from the Historical Period driven primarily by general inflationary pressures, storm response, and regulatory compliance. Please note Steam and Nuclear Generation do not include fuel.

Figure SAS-1. O&M Summary ($000), Total Company

	Operations and Maintenance Expense					
Item	**2018**	**2019**	**2020**	**2021**	**2022**	**TY 2024**
Steam Generation	$ 121,299	$ 106,972	$ 102,602	$ 106,281	$ 94,350	$ 23,788
Nuclear Generation	$ 257,277	$ 248,374	$ 240,256	$ 226,509	$ 242,824	$ 254,281
Hydro Generation	$ 5,018	$ 4,319	$ 3,206	$ 2,914	$ 3,676	$ 10,147
Other Generation	$ 6,882	$ 6,062	$ 4,624	$ 7,825	$ 4,321	$ 1,689
Transmission	$ 125,182	$ 172,146	$ 185,163	$ 237,810	$ 262,525	$ 314,132
Distribution	$ 81,401	$ 81,866	$ 74,701	$ 76,665	$ 85,297	$ 90,379
Customer and Information	$ 52,365	$ 60,265	$ 59,529	$ 30,511	$ 33,138	$ 49,884
Sales	$ 215	$ 272	$ 435	$ 522	$ 595	$ 282
Administrative and General	$ 95,144	$ 101,839	$ 96,746	$ 112,140	$ 97,739	$ 105,631
Total O&M Expense	**$ 744,782**	**$ 782,117**	**$ 767,263**	**$ 801,177**	**$ 824,463**	**$ 850,214**
Total O&M Expense (ExcludingTransmission)	**$ 619,601**	**$ 609,971**	**$ 582,099**	**$ 563,366**	**$ 561,939**	**$ 536,082**

1. Steam Generation reflects the expiration of the Rockport Unit 2 lease, which reduces overall Generation O&M as discussed by Company witness Jessee.
2. The Nuclear forecast increase in 2024 is primarily driven by outage amortization and inflation related to services and material costs as addressed by Company witness Ferneau.
3. The Hydro forecast includes expenses of regulatory compliance related costs as discussed by Company witness Jessee.
4. The Distribution forecast increase in 2024 is primarily driven by storm restoration expenses, supply chain constraints, and overall inflation as discussed by Company witness Isaacson.
5. Customer and Information O&M increase is driven by an increase in Demand Side Management/Energy Efficiency (DSM/EE) related costs that are addressed in the DSM/EE plan filing.
6. Administrative & General (A&G) O&M increases are primarily driven by an increase in salaries.

Q30. Please discuss the level of transmission revenues and expenses in the Test Year forecast and how it compares to the Historical Period.

In Attachment SAS-6*,* I show the operating revenues and expenses associated with all transmission activities in order to reflect the net effect of various offsetting accounts to provide a Total Company view of the transmission revenue and expenses. The net transmission expenses can be broken down into two categories.

The first category is the Load Serving Entity (LSE) - PJM open access transmission tariff (OATT) transmission expenses, which includes the costs incurred by I&M for use of the PJM transmission system to serve its customers. The PJM OATT expenses were $382 million in 2022 and are expected to increase in the Test Year to $443 million. The increase is primarily related to the Network Integration Transmission Service expenses reflecting the projected growth in transmission investments made within PJM. Company witness Koehler discusses this in more detail.

The second category, transmission-related revenue and expenses, is associated with transmission owner revenues and other transmission O&M expenses, the majority of which are the traditional embedded costs for I&M to operate and maintain its own transmission assets. This category is removed from the Company's cost of service, as discussed by Company witness Fischer.

Q31. Is the level of operations and maintenance expense included in the Test Year reasonable, accurate and representative of I&M's going forward costs?

Yes. The Test Year level of operations and maintenance expense is accurate, reasonable, and representative of I&M's going forward cost of providing service. Adjustments to the forecasted operations and maintenance expenses are addressed by other Company witnesses. Further, the reasonableness of the adjustments as sponsored by other Company witnesses are addressed in their respective testimony.

VI. Fuel, Consumables, Allowances, and Purchased Power

Q32. Please discuss the components of the Generation forecast.

The components of the Generation forecast are as follows:

1) *Fuel* - Fuel costs include both fossil and nuclear generation costs.

2) *Consumables* - I&M currently consumes activated carbon, anhydrous ammonia and sodium bicarbonate at the Rockport Plant. Company witness Jessee discusses this in more detail.

3) *Allowances* - I&M uses emission allowances to comply with Title IV of the Clean Air Act Amendments and the U.S. Environmental Protection Agency's Cross-State Air Pollution Rule (CSAPR). Company witness Jessee discusses allowances in more detail.

4) *Purchased Power* – Purchased power includes purchases from AEP Generating Company (AEG) - Rockport Unit 1, purchases from the Ohio Valley Electric Corporation, wind purchases and other system purchases.

   Also included in purchased power are:

   a. *PJM Ancillaries* - Include charges and credits, where applicable, for ancillary services such as operating reserves, reactive services, black start, spinning reserves, and regulation service.

   b. *Financial Transmission Rights (FTR) Revenue Net of Congestion* - Within PJM, members receive FTR revenues and incur congestion costs, which may or may not offset each other. FTRs are financial instruments that entitle the holder to receive compensation for certain congestion-related costs that arise when the transmission grid is heavily used. Simply put, FTRs are a partial hedge against transmission congestion costs. Congestion costs are measured as the difference in the price of megawatts for the generators in PJM versus the load serving entities.

c. *Transmission Losses* - PJM transmission losses include costs and credits associated with the financial settlement of physical losses (power losses due to resistance) on the transmission system within PJM.

Q33. Please discuss the level of fuel, consumables, allowances, and purchased power expense included in the Test Year.

As shown on Attachment SAS-5, fuel, consumables, allowances, and purchased power expense, excluding any ratemaking adjustments, is projected to be $529 million for the Test Year compared to $892 million in 2022. The $364 million projected decrease is primarily driven by the removal of Rockport Unit 2, leading to a decrease in fuel costs for fossil generation, a corresponding decrease in consumables, and a decrease in purchased power expense from AEG and non-affiliates. In addition, forecasted purchased power volumes are lower than experienced in 2022 due to lower forecasted market energy prices as well as refueling outages at the Cook Nuclear plant in 2022 as addressed by Company witness Ferneau.

Q34. Is the level of fuel, consumables, allowances and purchased power expense included in the Test Year reasonable, accurate, and representative of I&M's going forward costs?

Yes. The Test Year level of fuel, consumables, allowances and purchased power expense, as adjusted by the Company, is accurate, reasonable, and representative of I&M's going forward cost of providing service.

VII. Depreciation and Amortization

Q35. What are the major components of depreciation and amortization expense that are included in the Test year?

The major components of depreciation and amortization expense included in the Test Year are depreciation expense and amortization of plant

Q36. What is the level of depreciation and amortization expense that is included in the Test Year?

As shown on Attachment SAS-1, depreciation and amortization expense is projected to be $491 million for the Test Year, excluding ratemaking adjustments compared to $456 million in 2022.

The forecasted depreciation expense projection was developed, on a Total Company basis, by applying the composite depreciation rates approved by this Commission, the Michigan Public Service Commission (MPSC), and FERC to projected monthly plant in service balances. Company witness Cash further addresses depreciation expense.

As shown on Attachment SAS-8, I&M's plant in service is projected to increase by approximately $856 million from 2022 through the Test Year, excluding ratemaking adjustments. Based upon this plant in service projection, the approximately $35 million increase in depreciation and amortization expense is reasonable.

Q37. Is the level of depreciation and amortization expense included in the Test Year reasonable, accurate and representative of I&M's going forward costs?

Yes. The Test Year level of depreciation and amortization expense, as adjusted by the Company, is accurate, reasonable, and representative of I&M's going forward cost of providing service.

VIII. Taxes

Q38. What are the major components of taxes other than income taxes that are included in the Test Year?

The major components of taxes other than income taxes are revenue taxes, payroll taxes, and property taxes. These Test Year expenses are sponsored by Company witness Criss.

Q39. What is the level of taxes other than income taxes included in the Test Year?

Taxes other than income taxes, as shown on Attachment SAS-1, are projected to be $87 million for the Test Year, excluding any ratemaking adjustments, compared to $95 million in 2022. The primary driver of the decrease is associated with lower revenue taxes. It should also be noted that the utility receipts tax (URT), Ind. Code Article 6-2.3, was repealed July 1, 2022 and removed from I&M rates and is therefore not included in the forecast but was included in 2022 until July 1, 2022.[1]

Q40. What are the major components of income taxes that are included in the Test Year?

The major components of income taxes are federal income taxes, including both current and deferred taxes, state income taxes, and investment tax credit amortization related to credits generated prior to 2020. These Test Year expenses are sponsored by Company witness Criss.

Q41. What is the level of income taxes included in the Test Year?

As shown on Attachment SAS-1, income taxes are projected to be a benefit of $90 million for the Test Year, excluding any ratemaking adjustments, compared

[1] URT repealed per Ind. P. L. 138-2022, Sec. 3. I&M's 30-Day Filing, No. 50508, to remove URT was approved by the Commission on June 28, 2022.

to being unfavorable by $3 million in 2022. This is largely due to tax credits as addressed by Company witness Criss.

IX. Capital Forecast

Q42. Please describe the Capital Forecast Period in this case.

The Capital Forecast Period presented in this case is defined as January 2023 through December 2024. Company witnesses, Jessee, Ferneau, Isaacson, Koehler, and Brenner provide further support for the projected level of capital expenditures included in the Test Year.

Q43. Have you reviewed the level of capital costs included in the Capital Forecast period for reasonableness?

Yes. I have evaluated the capital included in the Capital Forecast period and compared this to actual capital expenditures in previous years, including the Historical Period. Attachment SAS-4 provides a summary of actual capital expenditures for the years 2018 through 2022 and the forecasted capital expenditures for the Capital Forecast Period. As a result of this review, I find that the Test Year level of capital investments proposed in this case, as compared to prior years, and particularly taking into consideration inflation, to be reasonable, necessary, and representative of I&M's cost of providing service as addressed by the functional witnesses.

Q44. Have you provided project level details that support the work plans and capital expenditures in the Capital Forecast Period?

Yes. WP-SAS-9 Project Life File contains a list of all capital projects; capital expenditures by month during the Capital Forecast Period; and plant in-service information. All information is broken down by function (Distribution, Generation, Nuclear, Transmission, and Corporate).

X. Plant in Service

Q45. How was the forecasted Test Year Plant in Service balance developed?

In order to develop the Test Year plant in service balance, forecasted transfers from Construction Work in Progress (CWIP) are added to – and retirements are subtracted from – the beginning actual plant in service balance. The forecast begins with actual account balances as of December 31, 2022 as provided by Company witness Cash and adds forecasted capital expenditures for the Capital Forecast Period, which is defined as January 1, 2023 through December 31, 2024.

Forecasted transfers from CWIP are a function of both the forecast of capital expenditures in each year and forecasted in-service dates for each construction project based upon the work plans. Forecast retirements are based upon a five-year rolling average of retirements for each function except for major retirements, such as a generating unit or software project, which are forecasted individually.

Attachment SAS-7 provides a historical overview of the closings from CWIP, retirements, and depreciation and amortization expense from 2018 through 2022. Attachment SAS-8 then provides an unadjusted, forward-looking forecast of plant in service, CWIP, and accumulated depreciation balances for the Capital Forecast Period.

Q46. Please describe the balance of Plant in Service included in the Test Year.

As shown on Attachment SAS-8, the balance of plant in service is projected to be $11,809 million at the end of 2024, excluding any ratemaking adjustments. Plant in service increased by $856 million during the Capital Forecast Period.

Figure SAS2 provides a Total Company summary of the functional projected activity during the entire Capital Forecast Period of January 1, 2023 through December 31, 2024.

Figure SAS-2. Net Plant in Service Activity

	In $Millions		
Function	**Transfers from CWIP**	**Retirements**	**Net**
Fossil and Hydro	$68	($7)	$61
Nuclear	$134	($100)	$34
Transmission	$158	($63)	$96
Distribution	$620	($56)	$564
General & Intangible	$185	($83)	$102
Total	**$1,165**	**($310)**	**$856**

Q47. Is the projected Plant in Service balance in the forecast reasonable, accurate, and representative of I&M's going forward costs?

Yes. The Test Year plant in service balance, as adjusted by the Company, is reasonable, accurate, and representative of I&M's going forward cost of providing service.

XI. Construction Work in Progress

Q48. How is the forecast of CWIP developed, and what is its importance in this case?

The forecasted balance of CWIP in any given month is developed by starting with the beginning balance, adding in capital expenditures, adding AFUDC accruals, and deducting transfers to plant in service. The transfers to plant in service occur upon a project's forecasted completion or in-service date.

Then the project's total forecasted balance of CWIP, including AFUDC, is transferred into plant in service. While CWIP is not a component of rate base in the Indiana jurisdiction, these calculations determine the size and timing of total transfers to plant in service.

Q49. Please discuss the level of the CWIP balance that is included in the forecast.

As shown on Attachment SAS-8, I&M's CWIP balance was $257 million as of December 31, 2022 and is forecast to decrease to $217 million by the end of 2024. *Figure SAS3* provides a Total Company summary of the functional projected activity during the entire Capital Forecast Period.

Figure SAS-3. Construction Work in Progress Activity

	In $Millions			
Function	**Cash Construction**	**AFUDC**	**Transfers to EPIS**	**Net**
Fossil and Hydro	$57	$2	($68)	($8)
Nuclear	$139	$4	($134)	$9
Transmission	$142	$8	($158)	($8)
Distribution	$585	$11	($620)	($23)
General & Intangible	$173	$3	($185)	($9)
Total Company	**$1,097**	**$29**	**($1,165)**	**($40)**

*may not foot due to rounding

The forecast of cash construction or capital expenditures shown above includes many projects for each function.

XII. Accumulated Depreciation

Q50. How did you develop the forecasted accumulated depreciation balance?

In order to develop a forecast of accumulated depreciation, depreciation and amortization expenses are added – and retirements and removal expenditures are subtracted – from the December 31, 2022 actual accumulated depreciation balance.

Q51. Please discuss the accumulated depreciation balance that is included in the Test Year.

As shown on Attachment SAS-8, I&M's accumulated depreciation and removal reserve was $4,077 million as of December 31, 2022 and is projected to be $4,633 million at the end of 2024, excluding any ratemaking adjustments.

Figure SAS4 provides a Total Company summary of the functional projected activity during the entire Capital Forecast Period of January 1, 2023 through December 31, 2024.

Figure SAS-4. Depreciation Reserve

	In $Millions			
Function	**Depreciation/ Amortization Expense**	**Retirements**	**Removal Expenditures**	**Net**
Fossil and Hydro	$201	($7)	($1)	$193
Nuclear	$326	($100)	($5)	$221
Transmission	$95	($63)	($1)	$31
Distribution	$204	($56)	($41)	$107
General & Intangible	$129	($83)	($41)	$5
Total Company	**$955**	**($310)**	**($89)**	**$557**

XIII. Operating Revenues

Q52. Please describe the major components of I&M's operating revenues.

The major components of I&M's operating revenues are Indiana and Michigan retail sales, FERC wholesale sales, OSS, transmission revenues, and other operating revenues.

Q53. Please explain how Rockport Unit 2 is handled in the financial forecast presented.

With the exception of certain Rockport Unit 2 costs that remain recoverable in I&M's cost of service as addressed by Company witnesses Ross, Cash and Williamson, the financial forecast presented in this proceeding excludes ongoing costs and revenues associated with Rockport Unit 2

Q54. Please provide an overview of the retail and FERC wholesale sales included in the forecast.

As shown on Attachment SAS-2, Total Company retail and FERC wholesale sales are projected to be $2,119 million for the Test Year. Total Company retail and FERC wholesale sales include Indiana retail revenues, Michigan retail revenues, and FERC municipal and cooperative wholesale revenues.

Total Test Year Indiana retail revenues, excluding any ratemaking adjustments or the requested change in base rates, are projected to be $1,575 million.

Q55. How do the projected Test Year Indiana retail revenues compare to the historical revenues for 2022?

As reflected in Attachment SAS-2, in 2022 actual Indiana retail revenue was $1,696 million, and the projection for the Test Year is $1,575 million. The projected revenue decrease of approximately $121 million is due to a $73 million projected decrease in non-fuel and a projected decrease in fuel revenue of $48 million.

Q56. How do the Test Year FERC wholesale revenues compare to the historical revenues from 2022?

As shown in Attachment SAS-2, in 2022 actual FERC wholesale revenues were $211 million, and the projection for the Test Year is $171 million, excluding any ratemaking adjustments. The projected decrease of $39 million is primarily due to lower FERC wholesale non-fuel and fuel rates.

Q57. Please describe the level of OSS in the forecast and how it compares with the Historical Period.

OSS are sales made in PJM at market prices during hours when generation from I&M's generating units exceeds the Company's internal load. Total OSS include both the cost to serve the sale and the resulting margins.

As shown in Attachment SAS-2, excluding any ratemaking adjustments, OSS in 2022 were $330 million compared to $76 million in the Test Year, with OSS margins being $121 million in 2022 compared to $8 million in the Test Year. The decrease in OSS is primarily due to two factors. In the Historical Period, I&M had available the output from Rockport Unit 2 for OSS until the lease ended on December 7, 2022. The second driver is the 2022 actual PJM Around the Clock Market Price was considerably higher than the forecasted market price.

Q58. Please provide an overview of other operating revenues.

Other operating revenues include forfeited customer discounts, reconnection and other service fee revenue, pole attachment revenues and other rents, associated business development income, gains on the sale of emission allowances, and transmission revenues. Transmission revenues and O&M expenses were discussed earlier in my testimony regarding operations and maintenance expense.

Q59. Please discuss the level of other operating revenue in the Test Year forecast and how it compares with the Historical Period.

As shown in Attachment SAS-2, total other operating revenues for the Test Year, excluding any ratemaking adjustments and excluding transmission revenues, are projected to be $43 million, whereas the level in 2022 was $45 million. The slight decrease in other operating revenues is primarily due to decreased revenue from Renewable Energy Credits.

Q60. Is the level of operating revenues included in the forecast provided by I&M accurate, reasonable, and representative of the Test Year?

Yes, the Test Year level of forecasted operating revenues is accurate, reasonable, and representative of I&M's going forward cost of providing service. Adjustments to the forecasted operating revenues are addressed by other Company witnesses and supported in their testimony.

XIV. Forecast Adjustments

Q61. What is the purpose of Rate Base Adjustment No. 8?

Rate Base Adjustment No. 8 corrects an input value to the forecast model for Account 151. Due to an overstated beginning balance of Fuel Inventory an adjustment was made to decrease rate base by $38.7 million.

XV. Fuel Adjustment Clause Basing Point

Q62. What is the projected Test Year FAC basing point?

The FAC basing point for the Test Year is 12.981 mills per kWh, as shown on Attachment SAS-10. The Total Company fuel costs computed on an Indiana basis are estimated to be $270.5 million with a net energy requirement of 20,838 GWh.

Q63. Please provide a general description of the methodologies and assumptions used in the development of I&M's forecasted fuel costs and net energy requirements for the Test Year.

The projected costs consist of FERC Account 501 fossil and Account 518 nuclear fuel costs, as well as the allowable portion of purchased power, calculated in a manner typically called the FERC Net Energy Cost method.

In addition, the total cost of wind purchases and the associated energy are included, consistent with the Commission Orders in Cause Nos. 43328, 43750, 44034, and 44362. The components of the net energy requirements and costs are shown on Attachment SAS-10.

To the extent that I&M incurs costs to supply energy to non-affiliates, those costs are removed from I&M's net energy costs. This is the same methodology I&M used in its last two rate cases Cause Nos. 45235 and 45576 and the methodology I&M traditionally uses in Indiana fuel cost adjustment filings, a methodology the Commission has found to be reasonable.

Q64. Does this conclude your pre-filed verified direct testimony?

Yes.

VERIFICATION

I, Shelli A. Sloan, Director Financial Support and Special Projects of 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: 8/8/2023

Shelli A. Sloan

Indiana Michigan Power Company - Corp Consolidated
Operating Income Comparison
For the Unadjusted Test Year Ended December 31, 2024 As Compared to 2022 Historical Period
Amounts in ($000)

Line No.	Description	TY - 2024	2022 Actuals	Difference
1	**Operating Revenues**			
2	Retail Sales	$ 1,948,150	$ 2,067,137	$ (118,987)
3	FERC Wholesale Sales	$ 171,176	$ 210,567	$ (39,391)
4	Off System Sales	$ 76,394	$ 330,028	$ (253,633)
5	Other Operating Revenues	$ 90,364	$ 95,634	$ (5,270)
6	Gains from Disposition of Allowances	$ 2	$ -	$ 2
7	**Total Operating Revenues**	$ 2,286,087	$ 2,703,366	$ (417,279)
8				
9	**Fuel Related and Purchased Power Expense**			
10	Fuel	$ 153,059	$ 191,258	$ (38,198)
11	Consumables	$ 6,809	$ 852	$ 5,958
12	Allowances	$ 3,092	$ 190	$ 2,902
13	Purchased Power	$ 365,708	$ 700,037	$ (334,329)
14	**Total Fuel Related and Purchased Power Expense**	$ 528,668	$ 892,337	$ (363,668)
15				
16	**Operating and Maintenance Expense**			
17	Steam Generation (Non-Fuel)	$ 13,887	$ 93,308	$ (79,421)
18	Nuclear Generation (Non-Fuel)	$ 254,281	$ 242,824	$ 11,457
19	Hydraulic Generation	$ 10,147	$ 3,676	$ 6,471
20	Other Generation & Power Supply	$ 1,689	$ 5,302	$ (3,612)
21	Transmission	$ 308,811	$ 258,163	$ 50,648
22	Regional Market Expense	$ 5,321	$ 4,362	$ 960
23	Distribution	$ 90,379	$ 85,297	$ 5,083
24	Customer Information	$ 39,535	$ 23,388	$ 16,147
25	Sales	$ 282	$ 595	$ (313)
26	Administrative and General	$ 105,631	$ 97,739	$ 7,892
27	Factored Accounts Receivable	$ 10,349	$ 9,750	$ 599
28	Accretion	$ 4,294	$ 2,435	$ 1,859
29	Line of Credit Fees	$ 39	$ 1,336	$ (1,297)
30	Gain/Loss Disposition of Utility Plant	$ -	$ (631)	$ 631
31	**Total Operating and Maintenance Expense**	$ 844,646	$ 827,542	$ 17,104
32				
33	**Depreciation and Amortization Expense**			
34	Depreciation	$ 433,290	$ 402,691	$ 30,600
35	Amortization of Plant	$ 57,906	$ 61,848	$ (3,943)
36	Regulatory Debits/Credits	$ -	$ (8,587)	$ 8,587
37	**Total Depreciation and Amortization Expense**	$ 491,196	$ 455,952	$ 35,244
38				
39	**Taxes Other than Income Taxes**			
40	Revenue Taxes	$ 10	$ 11,247	$ (11,238)
41	Payroll Taxes	$ 13,580	$ 11,920	$ 1,659
42	Property Taxes	$ 73,244	$ 71,319	$ 1,925
43	Regulatory Fees	$ -	$ -	$ -
44	Other	$ 51	$ 46	$ 4
45	**Total Taxes Other than Income Taxes**	$ 86,884	$ 94,533	$ (7,649)
46				
47	**Allowance For Funds Used During Construction**			
48	AOFUDC	$ (12,718)	$ (9,770)	$ (2,948)
49	ABFUDC	$ (5,517)	$ (5,737)	$ 220
50	**Total Allowance For Funds Used During Construction**	$ (18,235)	$ (15,508)	$ (2,727)
51				
52	**Income Taxes**			
53	Current Federal Income Taxes	$ (49,770)	$ 44,548	$ (94,317)
54	Deferred Federal Income Taxes	$ (44,932)	$ (47,298)	$ 2,365
55	Investment Tax Credit	$ (3,893)	$ (5,034)	$ 1,140
56	State Income Tax	$ 8,775	$ 10,483	$ (1,708)
57	**Total Income Taxes**	$ (89,820)	$ 2,700	$ (92,520)
58				
59	**Total Operating Expenses**	$ 1,843,340	$ 2,257,556	$ (414,216)
60				
61	**Regulatory Operating Income**	$ 442,747	$ 445,809	$ (3,063)

Indiana Michigan Power Company - Corp Consolidated
Revenue Comparison
For the Unadjusted Test Year Ended December 31, 2024 As Compared to 2022 Historical Period
Amounts in ($000)

Line No.	Description	TY - 2024	2022 Actuals	Difference
1	**Operating Revenues**			
2	Indiana Retail Revenues			
3	Non-Fuel Revenues	$ 1,380,661	$ 1,453,253	$ (72,592)
4	Fuel Revenues	$ 194,526	$ 242,917	$ (48,390)
5	Total	$ 1,575,187	$ 1,696,169	$ (120,982)
6				
7	Michigan Retail Revenues			
8	Non-Fuel Revenues	$ 252,838	$ 246,233	$ 6,604
9	Fuel Revenues	$ 120,125	$ 124,734	$ (4,609)
10	Total	$ 372,963	$ 370,967	$ 1,995
11				
12	FERC Wholesale Revenues			
13	Non-Fuel Revenues	$ 124,565	$ 149,416	$ (24,851)
14	Fuel Revenues	$ 46,612	$ 61,151	$ (14,539)
15	Total	$ 171,176	$ 210,567	$ (39,391)
16				
17	**Retail, Firm and Interruptible Sales**	**$ 2,119,326**	**$ 2,277,704**	**$ (158,378)**
18				
19	OSS Margin	$ 8,266	$ 120,710	$ (112,444)
20	OSS Cost Recovery	$ 68,128	$ 209,657	$ (141,529)
21	Other Sales for Resale	$ -	$ (340)	$ 340
22	**Off-System Sales**	**$ 76,394**	**$ 330,028**	**$ (253,633)**
23				
24	Forfeited Discounts	$ 5,378	$ 5,622	$ (244)
25	Miscellaneous Service Revenues	$ 3,354	$ 1,917	$ 1,437
26	Sales of Renew. Energy Credits	$ 17,558	$ 19,667	$ (2,109)
27	Rent from Electric Property	$ 13,021	$ 13,036	$ (15)
28	Other Electric Revenues - ABD & Other	$ 3,762	$ 4,699	$ (937)
29	Subtotal	$ 43,073	$ 44,940	$ (1,867)
30	PJM OATT Transmission Expense	$ (158,888)	$ (143,221)	$ (15,667)
31	Transmission Owner and Other Revenues	$ 206,179	$ 193,915	$ 12,264
32	Subtotal	$ 47,291	$ 50,694	$ (3,403)
33	**Other Operating Revenues/(Expense)**	**$ 90,364**	**$ 95,634**	**$ (5,270)**
34				
35	**Gains from Disposition of Allowances**	**$ 2**	**$ -**	**$ 2**
36	**Total Operating Revenues**	$ 2,286,087	$ 2,703,366	$ (417,279)

Indiana Michigan Power Company
Historic and Forecasted O&M Expenses
($000)

		Operations and Maintenance Expense					
Line	Item	2018	2019	2020	2021	2022	TY 2024
1	Steam Generation	$ 121,299	$ 106,972	$ 102,602	$ 106,281	$ 94,350	$ 23,788
2	Nuclear Generation	$ 257,277	$ 248,374	$ 240,256	$ 226,509	$ 242,824	$ 254,281
3	Hydro Generation	$ 5,018	$ 4,319	$ 3,206	$ 2,914	$ 3,676	$ 10,147
4	Other Generation	$ 6,882	$ 6,062	$ 4,624	$ 7,825	$ 4,321	$ 1,689
5	Transmission	$ 125,182	$ 172,146	$ 185,163	$ 237,810	$ 262,525	$ 314,132
6	Distribution	$ 81,401	$ 81,866	$ 74,701	$ 76,665	$ 85,297	$ 90,379
7	Customer and Information	$ 52,365	$ 60,265	$ 59,529	$ 30,511	$ 33,138	$ 49,884
8	Sales	$ 215	$ 272	$ 435	$ 522	$ 595	$ 282
9	Administrative and General	$ 95,144	$ 101,839	$ 96,746	$ 112,140	$ 97,739	$ 105,631
10	**Total O&M Expense**	**$ 744,782**	**$ 782,117**	**$ 767,263**	**$ 801,177**	**$ 824,463**	**$ 850,214**
11	**Total O&M Expense (ExcludingTransmission)**	**$ 619,601**	**$ 609,971**	**$ 582,099**	**$ 563,366**	**$ 561,939**	**$ 536,082**

		2024 Growth over Prior Years					
	Item	2018	2019	2020	2021	2022	Average
12	Steam Generation	-23.8%	-26.0%	-30.6%	-39.3%	-49.8%	-33.9%
13	Nuclear Generation	-0.2%	0.5%	1.4%	3.9%	2.3%	1.6%
14	Hydro Generation	12.5%	18.6%	33.4%	51.6%	66.2%	36.4%
15	Other Generation	-20.9%	-22.5%	-22.3%	-40.0%	-37.5%	-28.6%
16	Transmission	16.6%	12.8%	14.1%	9.7%	9.4%	12.5%
17	Distribution	1.8%	2.0%	4.9%	5.6%	2.9%	3.4%
18	Customer and Information	-0.8%	-3.7%	-4.3%	17.8%	22.7%	6.3%
19	Sales	4.6%	0.7%	-10.2%	-18.6%	-31.1%	-10.9%
20	Administrative and General	1.8%	0.7%	2.2%	-2.0%	4.0%	1.3%
21	**Total O&M Expense**	**2.2%**	**1.7%**	**2.6%**	**2.0%**	**1.5%**	**2.0%**
22	**Total O&M Expense (ExcludingTransmission)**	**-2.4%**	**-2.5%**	**-2.0%**	**-1.6%**	**-2.3%**	**-2.2%**

		Transmission O&M					
	Item	2018	2019	2020	2021	2022	TY 2024
23	Enhancement and Other PJM Costs	$ 7,459	$ 28,602	$ 21,328	$ 40,440	$ 31,878	$ 34,199
24	PJM NITS Costs	$ 90,838	$ 115,938	$ 140,814	$ 165,381	$ 207,470	$ 252,104
25	Other Transmission O&M	$ 26,884	$ 16,928	$ 26,884	$ 27,607	$ 23,177	$ 27,829
26	Total Transmission Expense	$ 125,182	$ 172,146	$ 185,163	$ 237,810	$ 262,525	$ 314,132

		2024 Transmission Growth over Prior Years					
	Item	2018	2019	2020	2021	2022	Average
27	Enhancement and Other PJM Costs	28.9%	3.6%	12.5%	-5.4%	3.6%	8.6%
28	PJM NITS Costs	18.5%	16.8%	15.7%	15.1%	10.2%	15.3%
29	Other Transmission O&M	0.6%	10.5%	0.9%	0.3%	9.6%	4.3%
30	Total Transmission Expense	16.6%	12.8%	14.1%	9.7%	9.4%	12.5%

		Distribution O&M					
	Item	2018	2019	2020	2021	2022	TY 2024
31	Vegetation Management Program Expense	$ 28,853	$ 29,953	$ 26,747	$ 30,667	$ 29,348	$ 32,153
32	Other Distribution O&M	$ 52,548	$ 51,913	$ 47,954	$ 45,998	$ 55,949	$ 58,226
33	Total Distribution Expense	$ 81,401	$ 81,866	$ 74,701	$ 76,665	$ 85,297	$ 90,379

		2024 Distribution Growth over Prior Years					
	Item	2018	2019	2020	2021	2022	Average
34	Vegetation Management Program Expense	1.8%	1.4%	4.7%	1.6%	4.7%	2.8%
35	Other Distribution O&M	1.7%	2.3%	5.0%	8.2%	2.0%	3.8%
36	Total Distribution Expense	1.8%	2.0%	4.9%	5.6%	2.9%	3.4%

		Customer and Information O&M					
	Item	2018	2019	2020	2021	2022	TY 2024
37	DSM Expense	$ 20,756	$ 23,096	$ 27,688	$ (798)	$ (237)	$ 13,580
38	Other Customer and Information O&M	$ 31,609	$ 37,168	$ 31,841	$ 31,309	$ 33,375	$ 36,304
39	Total Customer and Information Expense	$ 52,365	$ 60,265	$ 59,529	$ 30,511	$ 33,138	$ 49,884

		2024 Customer and Information Growth over Prior Years					
	Item	2018	2019	2020	2021	2022	Average
40	DSM Expense	-6.8%	-10.1%	-16.3%	n/a*	n/a*	-11.1%
41	Other Customer and Information O&M	2.3%	-0.5%	3.3%	5.1%	4.3%	2.9%
42	Total Customer and Information Expense	-0.8%	-3.7%	-4.3%	17.8%	22.7%	6.3%

*Cannot calculate compound annual growth rate when the beginning value is negative.

Indiana Michigan Power Company
Historic and Forecasted Capital Expenditures
Excluding AFUDC
($000)

	Actual					Forecast	
Fully Functionalized View	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Nuclear Generation	174,855	150,361	67,880	58,891	90,010	70,856	67,976
Generation (Steam/Hydro/Renew	39,550	63,131	65,296	17,530	16,831	25,415	32,022
Transmission	80,314	89,767	99,687	98,639	78,215	74,956	67,126
Distribution	205,988	199,048	191,925	238,914	298,705	296,668	288,699
Corporate (Intangible & General)	51,247	64,342	84,810	91,411	59,654	91,091	82,288
Total Capital Expense	**551,955**	**566,649**	**509,600**	**505,384**	**543,415**	**558,986**	**538,110**

Indiana Michigan Power Company - Corp Consolidated
Fuel, Consumables, Allowances and Purchased Power Comparison
For the Unadjusted Test Year Ended December 31, 2024 As Compared to 2022 Historical Period
Amounts in ($000)

Line No.	Description	TY- 2024	2022 Acutals	Difference
1	**Fuel**			
2	Fossil Generation	$ 48,764	$ 104,981	$ (56,217)
3	Nuclear Generation	$ 104,296	$ 86,277	$ 18,019
4	**Total Fuel Costs**	$ 153,059	$ 191,258	$ (38,198)
5				
6	**Consumables**			
7	Lime Hydrate	$ -	$ 0	$ (0)
8	Activated Carbon	$ 1,370	$ 2,572	$ (1,202)
9	Anhydrous Ammonia	$ 580	$ 1,037	$ (456)
10	Sodium Bicarbonate	$ 4,859	$ 13,928	$ (9,069)
11	DSI Rider Over/Under	$ -	$ 552	$ (552)
12	Consumables Expense Deferred	$ -	$ (17,236)	$ 17,236
13	**Total Consumables**	$ 6,809	$ 852	$ 5,958
14				
15	**Allowances**	3,092	$ 190	$ 2,902
16				
17	**Purchased Power**			
18	Purchased Power Non-Affil	$ 90,338	$ 268,853	$ (178,515)
19	Purchased Power - Wind	$ 83,176	$ 80,598	$ 2,579
20	Purchased Power - AEG	$ 129,967	$ 229,054	$ (99,087)
21	PJM Ancillaries	$ 11,739	$ 19,972	$ (8,233)
22	FTR Revenue Net of Congestion - LSE	$ 29,557	$ 26,298	$ 3,259
23	Transmission Losses	$ 15,198	$ 17,826	$ (2,628)
24	Riders - Over-/Under-recovery	$ 5,733	$ 57,436	$ (51,703)
25		$ 365,708	$ 700,037	$ (334,329)
26				
27	**Total Fuel Related and Purchased Power Expense**	$ 528,668	$ 892,337	$ (363,668)

Indiana Michigan Power Company - Corp Consolidated
Total Company Net Transmission Expenses Comparison
For the Unadjusted Test Year Ended December 31, 2024 As Compared to 2022 Historical Period
Amounts in ($000)

Line No.	Description	TY - 2024	2022 Actuals	Difference
1	Network Integration Transmission Service Charges	$ 412,674	$ 354,014	$ 58,660
2	(Accts 4561035, 5650016, 5650021)			
3	Firm and Non-Firm Point to Point Transmission Credits	$ (4,851)	$ (5,707)	$ 856
4	(Acct 4561005)			
5	Schedule 1A Ancillary Service Charges	$ 890	$ (679)	$ 1,569
6	(Transmission Owner Scheduling, System Control and Load Dispatching)			
7	(Accts 4561036, 5650015)			
8	PJM Transmission Enhancement Charges	$ 24,061	$ 25,901	$ (1,840)
9	(Accts 4561060, 5650012, 5650019)			
10	PJM Administrative Charges	$ 9,809	$ 8,711	$ 1,098
11	(Accts 5614001, 5618001, 5757001)			
12	RTO Start-up Cost Recovery Charges	$ -	$ -	$ -
13	(Acct 4561002 Gen only)			
14	**Load Serving Entity - PJM OATT Transmission Expenses**	**$ 442,583**	**$ 382,240**	**$ 60,342**
15				
16	Transmission Owner and Other Revenues	$ (206,179)	$ (193,915)	$ (12,264)
17	Transmission Owner and Other O&M Expenses	$ 30,220	$ 20,862	$ 9,358
18	**Transmission Owner - Transmission Revenues**	**$ (175,959)**	**$ (173,053)**	**$ (2,906)**
19				
20	**Total Company Net Transmission Expenses**	**$ 266,623**	**$ 209,187**	**$ 57,436**

Indiana Michigan Power Company - Corp Consolidated
Historic Functional Plant Activity
($000)

Line No.	Function	2018	2019	2020	2021	2022
1		**Closings from CWIP**				
2	Fossil, Hydro, and Other	$ 21,591	$ 13,895	$ 120,363	$ 53,937	$ 25,495
3	Nuclear	$ 478,358	$ 287,946	$ 74,502	$ 101,776	$ 179,470
4	Transmission	$ 106,773	$ 94,740	$ 87,129	$ 108,935	$ 73,637
5	Distribution	$ 210,730	$ 216,142	$ 189,676	$ 235,112	$ 274,496
6	General & Intangible	$ 66,265	$ 61,233	$ 69,023	$ 139,111	$ 59,298
7	**Total**	$ 883,717	$ 673,956	$ 540,693	$ 638,871	$ 612,396
8						
9		**Retirements**				
10	Fossil, Hydro, and Other	$ 2,679	$ 2,635	$ 5,792	$ 1,535	$ 8,959
11	Nuclear	$ 55,454	$ 88,858	$ 24,178	$ 13,299	$ 64,506
12	Transmission	$ 33,873	$ 29,752	$ 32,481	$ 22,201	$ 13,408
13	Distribution	$ 28,891	$ 28,272	$ 32,718	$ 29,579	$ 49,954
14	General & Intangible	$ 15,339	$ 20,477	$ 31,500	$ 16,228	$ 36,492
15	**Total**	$ 136,236	$ 169,994	$ 126,669	$ 82,842	$ 173,319
16						
17		**Depreciation & Amortization of Plant Expense**				
18	Fossil, Hydro, and Other	$ 76,729	$ 92,735	$ 109,000	$ 112,042	$ 114,459
19	Nuclear	$ 87,388	$ 110,027	$ 133,891	$ 141,774	$ 154,930
20	Transmission	$ 27,946	$ 30,810	$ 39,263	$ 42,024	$ 46,071
21	Distribution	$ 69,754	$ 82,678	$ 88,320	$ 94,767	$ 92,063
22	General & Intangible	$ 31,245	$ 33,592	$ 43,416	$ 49,170	$ 57,016
23	**Total**	$ 293,061	$ 349,842	$ 413,890	$ 439,777	$ 464,539

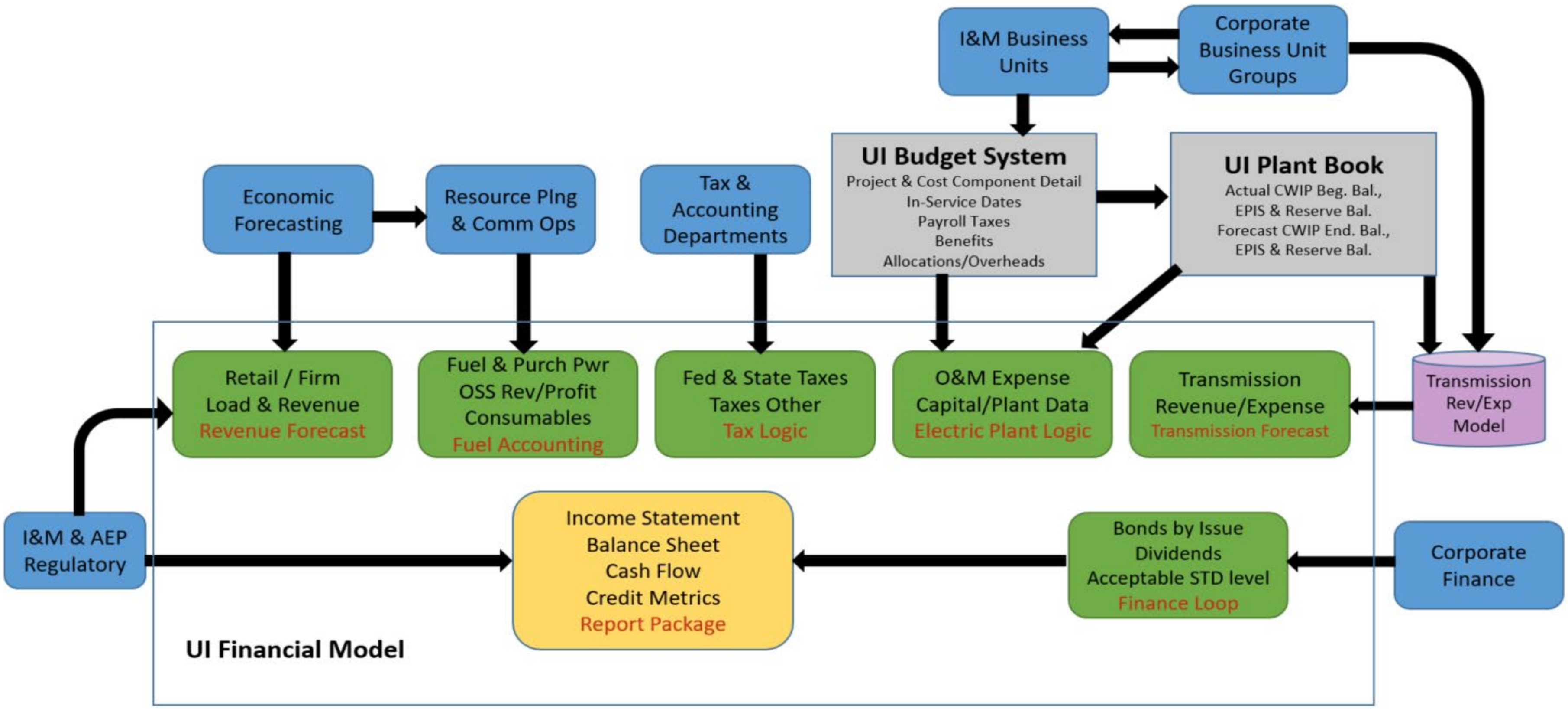
NOTES:
2018 through 2021 data is based on FERC Form 1.

Indiana Michigan Power Company - Corp Consolidated
Unadjusted Forecasted Functional Plant Balances
($000)

Line No.	Indiana Michigan Power Company - Corp I&M Plant Summary In Thousands ($000)	Historical 12/31/2022	Forecasted 12/31/2023	Test Year 12/31/2024
1	**Electric Plant In Service**			
2	Production - Fossil, Hydro & Other- Solar	1,396,960	1,417,994	1,457,752
3	Nuclear	4,110,223	4,129,642	4,143,842
4	Transmission	1,841,983	1,900,025	1,937,848
5	Distribution	3,024,512	3,351,295	3,588,407
6	General	211,400	236,059	284,958
7	Intangible	367,280	378,582	395,704
8	**Total Electric Plant In Service Balance (101 & 106)** Note 1	**10,952,358**	**11,413,596**	**11,808,511**
9	**Construction Work in Progress**			
10	Production - Fossil, Hydro, Other- Solar & Renewables activity	14,164	728	(34,273)
11	Nuclear activity	18,383	(527)	(13,980)
12	Transmission activity	84,054	4,576	(10,931)
13	Distribution activity	100,515	(2,167)	(1,947)
14	General Plant activity	26,815	3,383	348
15	Intangible Plant activity	12,717	180	39
16	**Total Constr Work in Progress Balance (107)**	**256,649**	**217,427**	**216,874**
17	**Accum. Prov for Depr. Amort. Depl**			
18	Production - Fossil, Hydro & Solar	(745,133)	(840,238)	(938,307)
19	Nuclear	(1,852,010)	(1,959,228)	(2,072,922)
20	Transmission	(488,944)	(503,868)	(519,623)
21	Distribution	(797,553)	(845,875)	(903,594)
22	General Plant	(47,295)	(48,565)	(52,072)
23	Intangible Plant	(145,989)	(146,994)	(146,468)
24	**Total Accumulated Depreciation Balance (108, 111, 115)** Note 1	**(4,076,923)**	**(4,344,768)**	**(4,632,986)**

Note 1: Does not include leases or plant held for future use. Does include leasehold improvements.

UI MODEL OVERVIEW



Indiana Michigan Power Company
Projected Fuel Adjustment Clause Factor
Basing Point Calculation for 2024 Test Year

Line No.		2024 TY
	ENERGY SOURCES - MWh	
1	Fossil Generation	1,372,238
2	Nuclear Generation	18,001,957
3	Hydro Generation	112,821
4	Solar Generation	63,399
5	AEG Purchases	1,372,238
6	OVEC Purchases	434,670
7	Wind Purchases	1,339,981
8	Other System Purchases	1,494,418
9	Less:	
10	Energy To Off-System Sales	2,618,565
11	Energy Losses and Company Use[Note 1]	735,645
12	Sales (S)	20,837,512
	FUEL COSTS	
13	Fossil Generation	40,218,025
14	Nuclear Generation	104,295,248
15	Post 4/7/83 Spent Nuclear Fuel	-
16	AEG Purchases	40,218,025
17	OVEC Purchases	14,222,414
18	Wind Purchases	83,176,196
19	Other System Purchases	44,801,281
20	Less:	
21	Energy To Off-System Sales	56,444,069
22	Total Fuel Costs (F)	270,487,120
23	(F) Divided by (S) Mills Per KWh	12.981
24	Current Basing Point (Mills Per KWh)	13.110
25	Fuel Clause Adjustment Factor (Mills Per KWh)	(0.129)

Note 1: The 3.41% line loss rate is based upon 2021 actual data per IURC Cause No. 38702-FAC89.