THIS FILING IS
Item 1: ☑ An Initial (Original) Submission OR ☐ Resubmission No.

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company) Indiana Michigan Power Company	Year/Period of Report End of: 2024/ Q4

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

I. Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q) is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities, Licensees, and Others Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

1. one million megawatt hours of total annual sales,
2. 100 megawatt hours of annual sales for resale,
3. 500 megawatt hours of annual power exchanges delivered, or
4. 500 megawatt hours of annual wheeling for others (deliveries plus losses).

III. What and Where to Submit

a. Submit FERC Form Nos. 1 and 3-Q electronically through the eCollection portal at https://eCollection.ferc.gov, and according to the specifications in the Form 1 and 3-Q taxonomies.

b. The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

c. Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:
Secretary
Federal Energy Regulatory Commission 888 First Street, NE
Washington, DC 20426

d. For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

a. Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

b. Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

Schedules	Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

e. The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of [COMPANY NAME] for the year ended on which we have reported separately under date of [DATE], we have also reviewed schedules [NAME OF SCHEDULES] of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases." The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

f. Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. Further instructions are found on the Commission's website at https://www.ferc.gov/ferc-online/ferc-online/frequently-asked-questions-faqs-efilingferc-online.

g. Federal, State, and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from https://www.ferc.gov/general-information-0/electric-industry-forms.

IV. When to Submit

FERC Forms 1 and 3-Q must be filed by the following schedule:

a. FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

b. FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,168 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 168 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

III. Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

V. Enter the month, day, and year for all dates. Use customary abbreviations. The "Date of Report" included in the header of each page is to be completed only for resubmissions (see VII. below).

VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

VII. For any resubmissions, please explain the reason for the resubmission in a footnote to the data field.

VIII. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

IX. Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

X. Schedule specific instructions are found in the applicable taxonomy and on the applicable blank rendered form.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and" firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

I. Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was

obtained and give date of the authorization.

II. Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

3. 'Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;
4. 'Person' means an individual or a corporation;
5. 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;
7. 'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; .....
11. "project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

a. 'To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304.

a. Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may by rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports shall be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309.

The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

GENERAL PENALTIES

The Commission may assess up to $1 million per day per violation of its rules and regulations. See FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

FERC FORM NO. 1
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent	02 Year/ Period of Report
Indiana Michigan Power Company	End of: 2024/ Q4

03 Previous Name and Date of Change (If name changed during year)
/

04 Address of Principal Office at End of Period (Street, City, State, Zip Code)
1 Riverside Plaza, Columbus, OH 43215-2373

05 Name of Contact Person	06 Title of Contact Person
Jason M. Johnson	Accountant

07 Address of Contact Person (Street, City, State, Zip Code)
1 Riverside Plaza, Columbus, OH 43215-2373

08 Telephone of Contact Person, Including Area Code	09 This Report is An Original / A Resubmission	10 Date of Report (Mo, Da, Yr)
614-716-1000	(1) ☑ An Original (2) ☐ A Resubmission	04/08/2025

Annual Corporate Officer Certification

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

01 Name	03 Signature	04 Date Signed (Mo, Da, Yr)
Jeffrey W. Hoersdig	Jeffrey W. Hoersdig	04/08/2025
02 Title		
Assistant Controller		

Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
	Identification	1	
	List of Schedules	2	
1	**General Information**	101	
2	**Control Over Respondent**	102	
3	**Corporations Controlled by Respondent**	103	
4	**Officers**	104	
5	**Directors**	105	
6	**Information on Formula Rates**	106	
7	**Important Changes During the Year**	108	
8	**Comparative Balance Sheet**	110	
9	**Statement of Income for the Year**	114	116-NA
10	**Statement of Retained Earnings for the Year**	118	
12	**Statement of Cash Flows**	120	
12	**Notes to Financial Statements**	122	
13	**Statement of Accum Other Comp Income, Comp Income, and Hedging Activities**	122a	
14	**Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep**	200	
15	**Nuclear Fuel Materials**	202	
16	**Electric Plant in Service**	204	
17	**Electric Plant Leased to Others**	213	
18	**Electric Plant Held for Future Use**	214	
19	**Construction Work in Progress-Electric**	216	
20	**Accumulated Provision for Depreciation of Electric Utility Plant**	219	
21	**Investment of Subsidiary Companies**	224	
22	**Materials and Supplies**	227	
23	**Allowances**	228	
24	**Extraordinary Property Losses**	230a	NA
25	**Unrecovered Plant and Regulatory Study Costs**	230b	NA
26	**Transmission Service and Generation Interconnection Study Costs**	231	
27	**Other Regulatory Assets**	232	
28	**Miscellaneous Deferred Debits**	233	
29	**Accumulated Deferred Income Taxes**	234	
30	**Capital Stock**	250	
31	**Other Paid-in Capital**	253	
32	**Capital Stock Expense**	254b	NA
33	**Long-Term Debt**	256	
34	**Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax**	261	
35	**Taxes Accrued, Prepaid and Charged During the Year**	262	
36	**Accumulated Deferred Investment Tax Credits**	266	
37	**Other Deferred Credits**	269	
38	**Accumulated Deferred Income Taxes-Accelerated Amortization Property**	272	
39	**Accumulated Deferred Income Taxes-Other Property**	274	
40	**Accumulated Deferred Income Taxes-Other**	276	
41	**Other Regulatory Liabilities**	278	
42	**Electric Operating Revenues**	300	
43	**Regional Transmission Service Revenues (Account 457.1)**	302	
44	**Sales of Electricity by Rate Schedules**	304	
45	**Sales for Resale**	310	
46	**Electric Operation and Maintenance Expenses**	320	

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
47	**Purchased Power**	326	
48	**Transmission of Electricity for Others**	328	
49	**Transmission of Electricity by ISO/RTOs**	331	NA
50	**Transmission of Electricity by Others**	332	
51	**Miscellaneous General Expenses-Electric**	335	
52	**Depreciation and Amortization of Electric Plant (Account 403, 404, 405)**	336	
53	**Regulatory Commission Expenses**	350	
54	**Research, Development and Demonstration Activities**	352	
55	**Distribution of Salaries and Wages**	354	
56	**Common Utility Plant and Expenses**	356	
57	**Amounts included in ISO/RTO Settlement Statements**	397	
58	**Purchase and Sale of Ancillary Services**	398	
59	**Monthly Transmission System Peak Load**	400	
60	**Monthly ISO/RTO Transmission System Peak Load**	400a	
61	**Electric Energy Account**	401a	
62	**Monthly Peaks and Output**	401b	
63	**Steam Electric Generating Plant Statistics**	402	
64	**Hydroelectric Generating Plant Statistics**	406	NA
65	**Pumped Storage Generating Plant Statistics**	408	NA
66	**Generating Plant Statistics Pages**	410	
66.1	**Energy Storage Operations (Large Plants)**	414	NA
66.2	**Energy Storage Operations (Small Plants)**	419	NA
67	**Transmission Line Statistics Pages**	422	
68	**Transmission Lines Added During Year**	424	
69	**Substations**	426	
70	**Transactions with Associated (Affiliated) Companies**	429	
71	**Footnote Data**	450	
	Stockholders' Reports (check appropriate box)		
	Stockholders' Reports Check appropriate box: ☐ Two copies will be submitted ☐ No annual report to stockholders is prepared		

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

Jeffrey W. Hoersdig

1 Riverside Plaza Columbus, Ohio 43215-2373

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

Indiana - February 21, 1925

State of Incorporation:

Date of Incorporation:

Incorporated Under Special Law:

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

(a) Name of Receiver or Trustee Holding Property of the Respondent:

(b) Date Receiver took Possession of Respondent Property:

(c) Authority by which the Receivership or Trusteeship was created:

(d) Date when possession by receiver or trustee ceased:

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

Electric - IndianaElectric - Michigan

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?
(1)
☐ Yes

(2)
☑ No

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the respondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiaries for whom trust was maintained, and purpose of the trust.

American Electric Power Company, Inc. - Ownership of 100% of Respondent's Common Stock

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Definitions

1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Price River Coal Company, Inc.	Coal Company - Inactive	100%	
2	Blackhawk Coal Company, Inc.	Coal Company - Inactive	100%	

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)	Date Started in Period (d)	Date Ended in Period (e)
1	[a] Footnote				

FOOTNOTE DATA

(a) Concept: OfficerTitle

Schedule Page: 104 Line No.: 1 Column: a

The following table provides summary information concerning compensation earned by our Chief Executive Officer, our former Chief Financial Officer; the three other most highly compensated executive officers; our former Interim President and Chief Executive Officer; and our former Chair of the Board, President, and Chief Executive Officer.We refer collectively to this group as the named executive officers (NEOs).

Name and Principal Position	Year	Salary ($)(1)	Bonus ($)(2)	Stock Awards ($)(3)	Non-Equity Incentive Plan Compensation ($)(4)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)(5)	All Other Compensation ($)(6)	Total ($)
William J. Fehrman								
President and Chief Executive Officer	2024	$ 628,846	$ 2,000,000	$ 9,469,144	$ 1,100,000	$ —	$ 59,032	$ 13,257,022
Charles E. Zebula								
Executive Vice President and Chief Financial Officer	2024	$ 724,327	$ —	$ 2,250,000	$ 605,840	$ 177,002	$ 85,564	$ 3,842,733
Greg B. Hall								
Executive Vice President and Chief Commercial Officer	2024	$ 575,491	$ —	$ 2,600,000	$ 485,416	$ 167,640	$ 70,977	$ 3,899,524
David M. Feinberg								
Executive Vice President, General Counsel and Secretary	2024	$ 771,628	$ —	$ 1,827,648	$ 447,448	$ 132,958	$ 77,057	$ 3,256,739
Therace M. Risch								
Executive Vice President, Chief Information and Technology Officer	2024	$ 684,906	$ —	$ 1,607,665	$ 536,999	$ 61,118	$ 35,400	$ 2,926,088
Ben Fowke								
Former Interim President and Chief Executive Officer	2024	$ 1,058,462	$ —	$ 8,060,780	$ 2,000,000	$ —	$ 210,777	$ 11,330,019
Julia A. Sloat								
Former Chair of the Board, President and Chief Executive Officer	2024	$ 327,692	$ —	$ —	$ —	$140,257	$ 2,454,334	$ 2,922,283

1.Amounts in the salary column are composed of executive salaries earned for the year shown, which include 262 days of pay for 2024, due to 2 additional workdays in 2024..

2.The amount in the bonus column for Mr. Fehrman reflects a negotiated hire bonus to be paid in 2024 following his hire as President and Chief Executive Officer on August 1.

3.The amounts reported in this column reflect the aggregate grant date fair value calculated in accordance with FASB ASC Topic 718 of the performance shares, restricted stock units (RSUs) and unrestricted shares granted under our Long-Term Incentive Plan. See Note 15 to the Consolidated Financial Statements included in our Form 10-K for the year ended December 31, 2024 for a discussion of the relevant assumptions used in calculating these amounts. The number of shares realized and the value of the performance shares, if any, will depend on the Company's performance during a 3-year performance period. The potential payout can range from 0 percent to 200 percent
of the target number of performance shares, plus any dividend equivalents. The value of the performance shares will be based on three measures: a Board approved cumulative operating earnings per share measure (Cumulative EPS 50%), a total shareholder return relative to peer companies (Relative TSR 40%) and a measure of generation capacity additions that maintain reliability through the clean energy transition (Maintaining Reliability 10%). The grant date fair value of the performance shares that are based on Cumulative EPS was computed in accordance with FASB ASC Topic 718 and was measured based on the closing price of AEP's common stock on the grant date. The maximum amount payable for the 2024 performance shares that are based on Cumulative EPS measured on the grant date is $3,500,000 for Mr. Fehrman, 825,000 for Mr. Hall, 1,237,500 for Mr. Feinberg, and $750,000 for Ms. Risch. The maximum amount payable for the 2024 performance shares that are based on Maintaining Reliability is $700,000 for Mr. Fehrman, $165,000 for Mr. Hall, $247,500 for Mr. Feinberg, and $150,000 for Ms. Risch. The grant date fair value of the 2024 performance shares that are based on Relative TSR is calculated using a Monte-Carlo model as of the date of grant, in accordance with FASB ASC Topic 718. Because the performance shares that are based on Relative TSR are subject to market conditions as defined under FASB ASC Topic 718, they did not have a maximum value on the grant date that differed from the grant date fair values presented in the table. Instead, the maximum value is factored into the calculation of the grant date fair value. The values realized from the 2022-2024 performance shares are included in the Option Exercises and Stock Vested for 2024 table.

4.The amounts shown in this column reflect annual incentive compensation paid for the year shown.

5.The amounts shown in this column are attributable to the increase in the actuarial values of each of the named executive officer's combined benefits under AEP's qualified and non-qualified defined benefit pension plans determined using interest rate and mortality assumptions consistent with those used in the Company's financial statements. See the Pension Benefits for 2024 table and related footnotes for additional information. See Note 8 to the Consolidated Financial Statements included in our Form 10-K for the year ended December 31, 2024 for a discussion of the relevant assumptions. None of the named executive officers received preferential or above-market earnings on deferred compensation.

6.Amounts shown in the All Other Compensation column for 2024 include: (a) Company matching contributions to the Company's Retirement Savings Plan, (b) Company matching contributions to the Company's Supplemental Retirement Savings Plan, (c) relocation, (d) perquisites, (e) vacation payout (f) severance benefits, and (g) director fees. Ms. Sloat's severance benefits, including amounts already paid, are subject to her compliance with the terms of a Severance, Release of All Claims and Noncompetition Agreement, which includes an agreement not to compete with the Company for two years. The value of each item included in 2024 All Other Compensation column is listed in the following table:

Type	William J. Fehrman (7)	Charles E. Zebula	Greg B. Hall	David M. Feinberg	Therace M. Risch	Ben Fowke (7)	Julia A. Sloat
Retirement Savings Plan Match	$ 15,006	$ 15,525	$ 15,525	$ 15,525	$ 15,525	$ 15,525	$ 15,525
Supplemental Retirement Savings Plan Match	$ 10,956	$ 27,620	$ 19,607	$ 30,766	$ —	$ 24,092	$ 35,697
Relocation	$ 21,559	$ —	$ —	$ —	$ —	$ —	$ —
Perquisites	$ 555	$ 14,799	$ 16,238	$ —	$ 19,875	$ 20,632	$ 21,223
Vacation Payout	$ —	$ —	$ —	$—	$ —	$ 69,231	$ 19,038
Severance	$ —	$ —	$ —	$ —	$ —	$ —	$ 2,326,154
Director Fees	$ —	$ —	$ —	$ —	$ —	$ 57,205	$ —
Total	**$ 48,076**	**$ 57,944**	**$ 51,370**	**$ 46,291**	**$ 35,400**	**$ 186,685**	**$ 2,417,637**

7.

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), name and abbreviated titles of the directors who are officers of the respondent.
2. Provide the principle place of business in column (b), designate members of the Executive Committee in column (c), and the Chairman of the Executive Committee in column (d).

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)	Member of the Executive Committee (c)	Chairman of the Executive Committee (d)
1	Julia A. Sloat, Chair of the Board and Chief Executive Officer	Columbus, Ohio	true	true
2	William J. Fehrman, Chair of the Board and Chief Executive Officer	Columbus, Ohio	true	true
3	Katherine K.Davis - Vice President - External Affairs and Customer Experience	Fort Wayne, Indiana	false	false
4	David M.Feinberg, Vice President and Secretary	Columbus, Ohio	true	false
5	Steven F.Baker - Chief Operating Officer and President	Fort Wayne, Indiana	true	false
6	Scott A. Huebner, Director Dist Region Opers	Fort Wayne, Indiana	false	false
7	Stephanny L Smith, Director Communications	Fort Wayne, Indiana	false	false
8	Charles E.Zebula Vice President and Chief Financial Officer	Columbus, Ohio	true	false
9	Nicholas M.Elkins - Director Customer and Business Services	Fort Wayne, Indiana	false	false
10	David S. Isaacson - Vice President - Distribution Region Operations	Fort Wayne, Indiana	false	false
11	Andrew J. Williamson - Director Regulatory Services	Fort Wayne, Indiana	false	false
12	Peggy I.Simmons,Vice President	Columbus, Ohio	true	false
13	Subin T.Mathew, Director Reliability & Grid Mod	Fort Wayne, Indiana	false	false
14	Benjamin G S. Fowke - Chair, Chief Executive Officer and Senior Advisor	Columbus, Ohio	true	false

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

INFORMATION ON FORMULA RATES

Does the respondent have formula rates?	☑ Yes ☐ No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number (a)	FERC Proceeding (b)
1	PJM Interconnection LLC - Attachment H-14	ER17-405

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

INFORMATION ON FORMULA RATES - FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?	☑ Yes ☐ No

2. If yes, provide a listing of such filings as contained on the Commission's eLibrary website.

Line No.	Accession No. (a)	Document Date / Filed Date (b)	Docket No. (c)	Description (d)	Formula Rate FERC Rate Schedule Number or Tariff Number (e)
1	20241031-5410	10/31/2024	ER17-405	AEP PJM OATT Proj Transmission	PJM OATT Attachment H-14
2	20240528-5349	05/28/2024	ER17-405	AEP PJM OATT Proj Transmission	PJM OATT Attachment H-14

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

INFORMATION ON FORMULA RATES - Formula Rate Variances

1. If a respondent does not submit such filings then indicate in a footnote to the applicable Form 1 schedule where formula rate inputs differ from amounts reported in the Form 1.
2. The footnote should provide a narrative description explaining how the "rate" (or billing) was derived if different from the reported amount in the Form 1.
3. The footnote should explain amounts excluded from the ratebase or where labor or other allocation factors, operating expenses, or other items impacting formula rate inputs differ from amounts reported in Form 1 schedule amounts.
4. Where the Commission has provided guidance on formula rate inputs, the specific proceeding should be noted in the footnote.

Line No.	Page No(s). (a)	Schedule (b)	Column (c)	Line No. (d)
1	204-207	Electric Plant in Service	g	49
2	214	Electric Plant Held for Future Use	d	46
3	216	Construction Work in Progress	b	1
4	219	Accumulated Depreciation	b	21
5	310-311	Sales for Resale	k	1
6	320	Electric Operations & Maintenance Expense	b	5
7	320	Electric Operations & Maintenance Expense	b	25
8	320	Electric Operations & Maintenance Expense	b	31
9	321	Electric Operations & Maintenance Expense	b	93
10	323	Electric Operations & Maintenance Expense	b	185
11	336	Depreciation Expense	b	7
12	354	Distribution of Wages and Salaries	b	28

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Pages 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

1.None

2. None

3. None

4. None

5. None

6. Issued: $80.36M Indiana Michigan Power Company nuclear fuel lease. State Authority: Cause No. 45806, Issued 4/29/2024, Maturity 10/29/2028

Terminated: $2,921,022 Letter of Credit issued by American Electric Power Company, Inc. on behalf of Indiana Michigan Power Company to benefit Nat'l Institute of Standards & Tech

7. None

8. 15 Cook Nuclear Plant Stores employees represented by IBEW #1392 were provided with a 2.5% CBA-Inclusion of MMT in BU increase effective March 19, 2024

74 Cook Nuclear Plant Maintenance employees represented by IBEW #1392 were provided with a 2.5% Wages increase effective April 1, 2024.
15 Cook Nuclear Plant Material Management employees represented by IBEW #1392 were provided with a 2.5% Wages increase effective April 1, 2024

76 Cook Nuclear Plant AEO/OPS employees represented by IBEW #1392 were provided with a 2.5% Wages increase effective April 1, 2024

56 Cook Nuclear Plant RPEC employees represented by IBEW #1392 were provided with a 2.5% Wages increase effective April 1, 2024

5 Cook Nuclear Plant QC/ NDE Techs employees represented by IBEW #1392 were provided with a 2.5% Contract increase effective May 19, 2024

72 River Transportation Division employees represented by USW #14811 were provided with a 2.5% Contract increase effective April 1, 2024.

133 South Bend, Elkhart , Benton Harbor, Buchanan, Mishawaka Hydro Group employees represented by IBEW #1392 were provided with a 2.5% Contract increase effective Nov 1, 2024.

98 Fort Wayne, Avilla, Decatur employees represented by IBEW #1392 were provided with a 2.5% Contract increase effective Nov 1, 2024.

75 Muncie, Marion employees represented by IBEW #1392 were provided with a 2.5% Contract increase effective Nov 1, 2024.

22 TLine – Niles, Ardmore, Delaware employees represented by IBEW #1392 were provided with a 2.5% Contract increase effective Nov 1, 2024.

3 South Maintenance Group employees represented by IBEW #1392 were provided with a 2.5% Contract increase effective Nov 1, 2024.

21 Three Rivers employees represented by IBEW #876 were provided with a 2.5% Contract increase effective Nov 1, 2024.

9. Please refer to the Notes to Financial Statements Pages 122-123

10. None

11. (Reserved)

13. Daniel E Mueller elected as Vice President - Tax effective on 01/27/2024 and resigned as Assistant Vice President - Tax effective on 01/26/2024

Noah K Hollis elected as Assistant Treasurer effective on 03/30/2024

Julia A Sloat resigned as Director, Chair of the Board, Chief Executive Officer effective on 02/25/2024

James X Llende resigned as Vice President - Tax effective on 01/25/2024

David P Hoffman elected as Vice President - Generation Assets effective on 01/20/2024 and resigned 7/1/2024

enee V Hawkins, resigned as Assistant Treasurer effective on 05/03/2024

icholas M Elkins, resigned as Director effective on 06/01/2024

cott A Huebner, elected as Director effective on 07/03/2024

Stephanny L Smith, elected as Director effective on 07/03/2024

William J Fehrman, elected as Chair of the Board, Chief Executive Officer, Director effective on 08/01/2024

Benjamin Fowke III, Director from 2/26/2024 through 8/26/2024; Senior Advisor effective on 08/01/2024 and also resigned as Director effective on 08/26/2024, as Senior Advisor effective on 10/22/2024 and as Chair of the Board and Chief Executive Officer effective on 07/31/2024

David M Feinberg, elected as Director effective on 09/26/2024

David S Isaacson, resigned as Vice President - Distribution Region Operations and Director effective on 07/01/2024

Peggy I Simmons resigned as Director effective on 09/23/2024 and resigned as Vice President 10/31/2024

Subin T Mathew elected as Director 6/1/2024 and resigned effective on 07/03/2024

Kelly J Ferneau, resigned as Site Vice president - Donald C. Cook plant effective on 10/31/2024

Scott A Dailey, elected as Site Vice president - Donald C. Cook plant effective on 11/01/2024

Matthew D Fransen, elected as Vice President and Treasurer effective on 12/01/2024

Shane Q. Lies resigned as Vice president effective on 10/31/2024

Julie A Sherwood, resigned as Vice president and Treasurer effective on 11/30/2024.

14. Proprietary capital ratio exceeds 30%

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200	11,620,089,566	11,377,231,808
3	Construction Work in Progress (107)	200	336,778,473	299,779,244
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		11,956,868,039	11,677,011,052
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	4,633,719,857	4,336,886,963
6	Net Utility Plant (Enter Total of line 4 less 5)		7,323,148,182	7,340,124,089
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202	143,286,121	83,395,796
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)			
9	Nuclear Fuel Assemblies in Reactor (120.3)		4,322,229	2,558,943
10	Spent Nuclear Fuel (120.4)		423,676,998	580,843,929
11	Nuclear Fuel Under Capital Leases (120.6)		[b]132,263,047	[b]153,808,147
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202	425,946,653	582,317,204
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		277,601,742	238,289,611
14	Net Utility Plant (Enter Total of lines 6 and 13)		7,600,749,924	7,578,413,700
15	Utility Plant Adjustments (116)		(1,865,381)	(1,234,593)
16	Gas Stored Underground - Noncurrent (117)			
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		684,838,274	683,974,696
19	(Less) Accum. Prov. for Depr. and Amort. (122)		603,048,716	595,584,094
20	Investments in Associated Companies (123)			
21	Investment in Subsidiary Companies (123.1)	224		
23	Noncurrent Portion of Allowances	228		7,271,212
24	Other Investments (124)		11,118,235	11,792,273
25	Sinking Funds (125)			
26	Depreciation Fund (126)			
27	Amortization Fund - Federal (127)			
28	Other Special Funds (128)		4,395,124,329	3,860,213,704
29	Special Funds (Non Major Only) (129)		197,581,364	180,519,109
30	Long-Term Portion of Derivative Assets (175)			11,818,600
31	Long-Term Portion of Derivative Assets - Hedges (176)			
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		4,685,613,486	4,160,005,500
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)			
35	Cash (131)		1,546,149	2,105,763
36	Special Deposits (132-134)		14,463,490	11,367,227
37	Working Fund (135)			
38	Temporary Cash Investments (136)			
39	Notes Receivable (141)			
40	Customer Accounts Receivable (142)		58,522,225	68,798,394
41	Other Accounts Receivable (143)		6,227,476	8,183,752
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		9,265	4,786
43	Notes Receivable from Associated Companies (145)			
44	Accounts Receivable from Assoc. Companies (146)		75,924,376	61,896,424
45	Fuel Stock (151)	227	79,612,046	84,069,956
46	Fuel Stock Expenses Undistributed (152)	227	3,749,464	3,988,855
47	Residuals (Elec) and Extracted Products (153)	227		
48	Plant Materials and Operating Supplies (154)	227	210,904,737	206,412,591
49	Merchandise (155)	227		
50	Other Materials and Supplies (156)	227	1,301,835	1,559,255

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
51	Nuclear Materials Held for Sale (157)	202/227		
52	Allowances (158.1 and 158.2)	228	2,408	7,539,887
53	(Less) Noncurrent Portion of Allowances	228		7,271,212
54	Stores Expense Undistributed (163)	227		
55	Gas Stored Underground - Current (164.1)			
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)			
57	Prepayments (165)		24,187,796	20,964,797
58	Advances for Gas (166-167)			
59	Interest and Dividends Receivable (171)			
60	Rents Receivable (172)		144,388	140,982
61	Accrued Utility Revenues (173)		21,446,535	241,058
62	Miscellaneous Current and Accrued Assets (174)		25,139,606	21,084,973
63	Derivative Instrument Assets (175)		18,442,795	39,610,905
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)			11,818,600
65	Derivative Instrument Assets - Hedges (176)			
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)			
67	Total Current and Accrued Assets (Lines 34 through 66)		541,606,061	518,870,221
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		20,759,191	22,281,512
70	Extraordinary Property Losses (182.1)	230a		
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b		
72	Other Regulatory Assets (182.3)	232	727,860,526	664,714,880
73	Prelim. Survey and Investigation Charges (Electric) (183)		5,650,316	11,799,921
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)			
75	Other Preliminary Survey and Investigation Charges (183.2)			
76	Clearing Accounts (184)			
77	Temporary Facilities (185)			
78	Miscellaneous Deferred Debits (186)	233	89,352,672	99,346,760
79	Def. Losses from Disposition of Utility Plt. (187)			
80	Research, Devel. and Demonstration Expend. (188)	352	9,104	
81	Unamortized Loss on Reaquired Debt (189)		10,889,124	11,793,731
82	Accumulated Deferred Income Taxes (190)	234	1,072,227,054	1,014,014,269
83	Unrecovered Purchased Gas Costs (191)			
84	Total Deferred Debits (lines 69 through 83)		1,926,747,987	1,823,951,073
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		14,752,852,076	14,080,005,901
		Page 110-111		

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: NuclearFuelUnderCapitalLeases
Includes 2024 costs in connection with nuclear leases: Finance charges - $9,493,857
(b) Concept: NuclearFuelUnderCapitalLeases
Includes 2023 costs in connection with nuclear leases: Finance charges - $6,471,425

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**PROPRIETARY CAPITAL**			
2	Common Stock Issued (201)	250	56,583,866	56,583,866
3	Preferred Stock Issued (204)	250		
4	Capital Stock Subscribed (202, 205)			
5	Stock Liability for Conversion (203, 206)			
6	Premium on Capital Stock (207)		4,234,635	4,234,635
7	Other Paid-In Capital (208-211)	253	1,007,436,399	993,410,869
8	Installments Received on Capital Stock (212)	252		
9	(Less) Discount on Capital Stock (213)	254		
10	(Less) Capital Stock Expense (214)	254b		127
11	Retained Earnings (215, 215.1, 216)	118	2,330,099,634	2,088,734,015
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118	(2,086,935)	(2,086,935)
13	(Less) Reacquired Capital Stock (217)	250		
14	Noncorporate Proprietorship (Non-major only) (218)			
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	327,549	(588,506)
16	Total Proprietary Capital (lines 2 through 15)		3,396,595,148	3,140,287,817
17	**LONG-TERM DEBT**			
18	Bonds (221)	256		
19	(Less) Reacquired Bonds (222)	256		
20	Advances from Associated Companies (223)	256		
21	Other Long-Term Debt (224)	256	3,381,505,475	3,368,102,458
22	Unamortized Premium on Long-Term Debt (225)			
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		9,167,506	9,718,152
24	Total Long-Term Debt (lines 18 through 23)		3,372,337,969	3,358,384,306
25	**OTHER NONCURRENT LIABILITIES**			
26	Obligations Under Capital Leases - Noncurrent (227)		119,587,050	140,206,676
27	Accumulated Provision for Property Insurance (228.1)			
28	Accumulated Provision for Injuries and Damages (228.2)		978,920	781,940
29	Accumulated Provision for Pensions and Benefits (228.3)		7,267,614	7,358,193
30	Accumulated Miscellaneous Operating Provisions (228.4)		995,504	851,241
31	Accumulated Provision for Rate Refunds (229)		42,428,363	13,931,002
32	Long-Term Portion of Derivative Instrument Liabilities		350,647	
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges			
34	Asset Retirement Obligations (230)		2,093,721,304	2,105,922,479
35	Total Other Noncurrent Liabilities (lines 26 through 34)		2,265,329,402	2,269,051,531
36	**CURRENT AND ACCRUED LIABILITIES**			
37	Notes Payable (231)			
38	Accounts Payable (232)		202,197,445	225,775,604
39	Notes Payable to Associated Companies (233)		126,833,824	63,309,819
40	Accounts Payable to Associated Companies (234)		98,544,503	107,351,786
41	Customer Deposits (235)		59,076,100	72,152,655
42	Taxes Accrued (236)	262	102,142,694	104,732,995
43	Interest Accrued (237)		41,281,144	41,295,071
44	Dividends Declared (238)			
45	Matured Long-Term Debt (239)			
46	Matured Interest (240)			
47	Tax Collections Payable (241)		7,503,634	7,127,317
48	Miscellaneous Current and Accrued Liabilities (242)		95,876,299	65,147,867
49	Obligations Under Capital Leases-Current (243)		87,078,421	99,593,043

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
50	Derivative Instrument Liabilities (244)		662,325	1,996,901
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		350,647	
52	Derivative Instrument Liabilities - Hedges (245)			
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges			
54	Total Current and Accrued Liabilities (lines 37 through 53)		820,845,742	788,483,058
55	**DEFERRED CREDITS**			
56	Customer Advances for Construction (252)			
57	Accumulated Deferred Investment Tax Credits (255)	266	13,837,485	15,772,724
58	Deferred Gains from Disposition of Utility Plant (256)			
59	Other Deferred Credits (253)	269	34,222,453	28,739,109
60	Other Regulatory Liabilities (254)	278	2,601,636,524	2,295,381,583
61	Unamortized Gain on Reacquired Debt (257)			
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272	9,042,366	11,939,902
63	Accum. Deferred Income Taxes-Other Property (282)		1,015,205,444	1,166,950,482
64	Accum. Deferred Income Taxes-Other (283)		1,223,799,543	1,005,015,390
65	Total Deferred Credits (lines 56 through 64)		4,897,743,815	4,523,799,190
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		14,752,852,076	14,080,005,902
	Page 112-113			

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

STATEMENT OF INCOME

Quarterly

1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable

6. Do not report fourth quarter data in columns (e) and (f)
7. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility column in a similar manner to a utility department. Spread the amount(s) over Lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
8. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11. Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purchases, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stockholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utiity Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
1	UTILITY OPERATING INCOME											
2	Operating Revenues (400)	300	2,417,893,836	2,305,195,850			2,417,893,836	2,305,195,850				
3	Operating Expenses											
4	Operation Expenses (401)	320	1,154,934,820	1,007,731,110			1,154,934,820	1,007,731,110				
5	Maintenance Expenses (402)	320	230,967,509	232,937,034			230,967,509	232,937,034				
6	Depreciation Expense (403)	336	419,808,812	406,335,551			419,808,812	406,335,551				
7	Depreciation Expense for Asset Retirement Costs (403.1)	336	2,517,737	2,052,740			2,517,737	2,052,740				
8	Amort. & Depl. of Utility Plant (404-405)	336	48,576,229	45,929,089			48,576,229	45,929,089				
9	Amort. of Utility Plant Acq. Adj. (406)	336										
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)											
11	Amort. of Conversion Expenses (407.2)											
12	Regulatory Debits (407.3)		15,745,910				15,745,910					
13	(Less) Regulatory Credits (407.4)		15,387,705	(5,660,713)			15,387,705	(5,660,713)				
14	Taxes Other Than Income Taxes (408.1)	262	84,827,986	80,452,744			84,827,986	80,452,744				
15	Income Taxes - Federal (409.1)	262	28,740,349	100,281,326			28,740,349	100,281,326				
16	Income Taxes - Other (409.1)	262	9,221,906	21,938,242			9,221,906	21,938,242				

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utiity Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
17	Provision for Deferred Income Taxes (410.1)	234, 272	377,503,434	349,865,531			377,503,434	349,865,531				
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272	433,536,061	411,668,406			433,536,061	411,668,406				
19	Investment Tax Credit Adj. - Net (411.4)	266	(1,935,239)	(1,577,975)			(1,935,239)	(1,577,975)				
20	(Less) Gains from Disp. of Utility Plant (411.6)		1,383,679	615,873			1,383,679	615,873				
21	Losses from Disp. of Utility Plant (411.7)		13,450,413	209,501			13,450,413	209,501				
22	(Less) Gains from Disposition of Allowances (411.8)		53	58			53	58				
23	Losses from Disposition of Allowances (411.9)											
24	Accretion Expense (411.10)		2,199,654	2,256,443			2,199,654	2,256,443				
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,936,252,022	1,841,787,712			1,936,252,022	1,841,787,712				
27	Net Util Oper Inc (Enter Tot line 2 less 25)		481,641,814	463,408,138			481,641,814	463,408,138				
28	Other Income and Deductions											
29	Other Income											
30	Nonutilty Operating Income											
31	Revenues From Merchandising, Jobbing and Contract Work (415)											
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)											
33	Revenues From Nonutility Operations (417)		187,864,741	194,622,278								
34	(Less) Expenses of Nonutility Operations (417.1)		218,388,876	185,175,348								
35	Nonoperating Rental Income (418)		256,963	553,976								
36	Equity in Earnings of Subsidiary Companies (418.1)	119		329,210								
37	Interest and Dividend Income (419)		960,812	2,577,052								
38	Allowance for Other Funds Used During Construction (419.1)		13,276,243	10,857,387								
39	Miscellaneous Nonoperating Income (421)		(1,379,690)	472,732								
40	Gain on Disposition of Property (421.1)		55,929	17,780								
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		(17,353,878)	24,255,067								
42	Other Income Deductions											

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utiity Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
43	Loss on Disposition of Property (421.2)			1,842								
44	Miscellaneous Amortization (425)											
45	Donations (426.1)		1,533,830	993,378								
46	Life Insurance (426.2)											
47	Penalties (426.3)		456,004	25,763								
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,100,336	778,192								
49	Other Deductions (426.5)		17,688,029	17,762,596								
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		20,778,199	19,561,771								
51	Taxes Applic. to Other Income and Deductions											
52	Taxes Other Than Income Taxes (408.2)	262	4,367,489	3,668,807								
53	Income Taxes-Federal (409.2)	262	(12,118,895)	(7,151,378)								
54	Income Taxes-Other (409.2)	262	(2,185,098)	(997,536)								
55	Provision for Deferred Inc. Taxes (410.2)	234, 272	11,856,635	16,511,805								
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272	72,776,192	8,943,666								
57	Investment Tax Credit Adj.-Net (411.5)											
58	(Less) Investment Tax Credits (420)											
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		(70,856,061)	3,088,032								
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		32,723,984	1,605,264								
61	Interest Charges											
62	Interest on Long-Term Debt (427)		135,301,504	130,890,015								
63	Amort. of Debt Disc. and Expense (428)		2,072,968	2,066,036								
64	Amortization of Loss on Reaquired Debt (428.1)		904,608	1,080,340								
65	(Less) Amort. of Premium on Debt-Credit (429)											
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)			1,284								
67	Interest on Debt to Assoc. Companies (430)		4,337,462	3,195,053								
68	Other Interest Expense (431)		(10,429,370)	(422,845)								
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		9,186,993	7,666,980								

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utiity Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
70	Net Interest Charges (Total of lines 62 thru 69)		123,000,179	129,140,335								
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		391,365,619	335,873,067								
72	Extraordinary Items											
73	Extraordinary Income (434)											
74	(Less) Extraordinary Deductions (435)											
75	Net Extraordinary Items (Total of line 73 less line 74)											
76	Income Taxes-Federal and Other (409.3)	262										
77	Extraordinary Items After Taxes (line 75 less line 76)											
78	Net Income (Total of line 71 and 77)		391,365,619	335,873,067								
						Page 114-117						

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly report.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436-439 inclusive). Show the contra primary account affected in column (b).
4. State the purpose and amount for each reservation or appropriation of retained earnings.
5. List first Account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items, in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown for Account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, attach them at page 122.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		2,083,602,852	1,960,690,274
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Adjustments to Retained Earnings Credit			
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	Adjustments to Retained Earnings Debit			
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		391,365,619	335,543,857
17	Appropriations of Retained Earnings (Acct. 436)			
17.1	Reclassification of Appropriated Retained Earnings-Amort Reserve Federal		(116,755)	(131,279)
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		(116,755)	(131,279)
23	Dividends Declared-Preferred Stock (Account 437)			
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
30.1	Dividends Declared-Common Stock		(150,000,000)	(212,500,000)
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		(150,000,000)	(212,500,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		2,324,851,716	2,083,602,852
39	APPROPRIATED RETAINED EARNINGS (Account 215)			
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		5,247,918	5,131,163
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		5,247,918	5,131,163
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		2,330,099,634	2,088,734,015
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account Report only on an Annual Basis, no Quarterly)			
49	Balance-Beginning of Year (Debit or Credit)		(2,086,935)	(2,416,145)
50	Equity in Earnings for Year (Credit) (Account 418.1)			329,210
51	(Less) Dividends Received (Debit)			
52	TOTAL other Changes in unappropriated undistributed subsidiary earnings for the year			
53	Balance-End of Year (Total lines 49 thru 52)		(2,086,935)	(2,086,935)

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

STATEMENT OF CASH FLOWS

1. Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
2. Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
3. Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
4. Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instructions No.1 for explanation of codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities		
2	Net Income (Line 78(c) on page 117)	391,365,619	335,873,067
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	470,902,779	454,317,381
5	Amortization of (Specify) (footnote details)		
5.1	Amortization of Regulatory Debits & Credits	358,205	5,660,713
5.2	Amortization of Nuclear Fuel	112,420,087	103,085,460
5.3	Accretion of Asset Retirement Obligation	2,199,654	2,256,443
8	Deferred Income Taxes (Net)	(116,952,184)	(54,234,737)
9	Investment Tax Credit Adjustment (Net)	(1,935,239)	(1,577,975)
10	Net (Increase) Decrease in Receivables	(1,777,838)	70,877,672
11	Net (Increase) Decrease in Inventory	462,573	(61,557,853)
12	Net (Increase) Decrease in Allowances Inventory	52,996	2,764,456
13	Net Increase (Decrease) in Payables and Accrued Expenses	(47,918,009)	28,702,804
14	Net (Increase) Decrease in Other Regulatory Assets	14,418,738	24,521,227
15	Net Increase (Decrease) in Other Regulatory Liabilities	(49,274,590)	(52,439,268)
16	(Less) Allowance for Other Funds Used During Construction	13,276,243	10,857,387
17	(Less) Undistributed Earnings from Subsidiary Companies		329,210
18	Other (provide details in footnote):		
18.1	Other (provide details in footnote):	[a](5,550,833)	(67,308,354)
18.2	Mark-to-Market of Risk Management Contracts	19,833,537	(22,198,465)
18.3	Over/Under Recovered Fuel,Net	(8,618,835)	55,947,745
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	766,710,417	813,503,719
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	(598,072,562)	(567,288,538)
27	Gross Additions to Nuclear Fuel	(142,870,346)	(129,871,313)
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	(218,479)	(272,640)
30	(Less) Allowance for Other Funds Used During Construction	(13,276,243)	(10,857,387)
31	Other (provide details in footnote):		
31.1	Other (provide details in footnote):		
31.2	Acquired Assets	(683,701)	(1,274,829)
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(728,568,845)	(687,849,933)
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	[b]1,747,883	1,972,268
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Disposition of Investments in (and Advances to) Associated and Subsidiary Companies		
44	Purchase of Investment Securities (a)	(2,902,355,285)	(2,845,119,721)
45	Proceeds from Sales of Investment Securities (a)	2,851,150,181	2,787,538,306
46	Loans Made or Purchased		

Line No.	Description (See Instructions No.1 for explanation of codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
47	Collections on Loans		
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
53.1	Sale of Barges		
53.2	Other (provide details in footnote):	(a)5,413,161	5,423,627
53.3	(increase) Decrease in Other Special Deposits	(877,853)	(925,231)
53.4	Note Receivable from Associated Companies		
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(773,490,758)	(738,960,683)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		500,000,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
64.1	Capital Contributions from Parent	14,025,530	8,774,270
64.2	Long Term Issuance Costs		(5,157,840)
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
67.1	Proceeds on Acquired Assets	816,102	826,096
67.2	Notes Payable to Associated Companies	63,524,005	
67.3	Proceeds on Nuclear Fuel Leaseback	80,360,000	70,440,000
70	Cash Provided by Outside Sources (Total 61 thru 69)	158,725,637	574,882,526
72	Payments for Retirement of:		
73	Long-term Debt (b)	(2,504,911)	(252,359,390)
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
76.1	Other (provide details in footnote):		
76.2	Notes Payable to Associated Companies - Retired		(186,631,145)
78	Net Decrease in Short-Term Debt (c)		
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	(150,000,000)	(212,500,000)
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	6,220,726	(76,608,009)
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	Net Increase (Decrease) in Cash and Cash Equivalents (Total of line 22, 57 and 83)	(559,615)	(2,064,973)
88	Cash and Cash Equivalents at Beginning of Period	2,105,764	4,170,737
90	Cash and Cash Equivalents at End of Period	1,546,149	2,105,764

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: OtherAdjustmentsToCashFlowsFromOperatingActivities

	2024 Cash Flow Incr / (Decr)	2023 Cash Flow Incr / (Decr)
Utility Plant, Net	$ (142,536,445)	$ (141,621,280)
Property and Investments, Net	17,417,075	32,048,324
Margin Deposits	(2,218,410)	(9,072,810)
Prepayments	(8,811,785)	(30,273,435)
Accrued Utility Revenues, Net	(21,205,479)	316,195
Miscellaneous Current and Accr Assets	(5,214,179)	5,057,953
Unamortized Debt Expense	1,522,322	1,297,020
Other Deferred Debits, Net	16,811,409	(30,266,632)
Proprietary Capital, Net	—	
Other Comprehensive Income, Net	436,883	(353,078)
Unamortized Discount/Premium on Long-Term Debt	550,646	556,493
Accumulated Provisions - Misc	28,968,077	3,049,636
Current and Accrued Liabilities, Net	21,089,746	7,567,257
Other Deferred Credits, Net	87,639,307	94,386,003
Total	**$ (5,550,833)**	**$ (67,308,354)**

(b) Concept: ProceedsFromDisposalOfNoncurrentAssets

	2024 Cash Flow Incr / (Decr)	2023 Cash Flow Incr / (Decr)
Sale of transformers between various operating companies	$ 874,329	$ 853,534
Sale of meters between various operating companies	127,716	338,301
Transco Transfer of Assets	14,536	111,481
Land Sale of Buchanan Nuclear Headquarters 19.19+/- acres in Buchanan, MI		196,670
Sale of Mobile Station Assets from I&M-D to OPCo-D Mobile Station		472,282
Sale of IM-D Skid Station IMCO-1005 SN N36672 to SWEPCo-D Skid Station SW-1003	731,302	
Total	**$ 1,747,883**	**$ 1,972,268**

(c) Concept: OtherAdjustmentsToCashFlowsFromInvestmentActivities

	2024 Cash Flow Incr / (Decr)	2023 Cash Flow Incr / (Decr)
DOE Reimbursemnt	$ 3,546,824	$ 2,572,539
CIAC Proceeds	1,866,337	2,851,088
Total	**$ 5,413,161**	**$ 5,423,627**

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Commission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

INDEX OF NOTES TO FINANCIAL STATEMENTS

	Glossary of Terms for Notes
1.	Organization and Summary of Significant Accounting Policies
2.	New Accounting Standards
3.	Comprehensive Income
4.	Rate Matters
5.	Effects of Regulation
6.	Commitments, Guarantees and Contingencies
7.	Benefit Plans
8.	Business Segments
9.	Derivatives and Hedging
10.	Fair Value Measurements
11.	Income Taxes
12.	Leases
13.	Voluntary Severance Program
14.	Financing Activities
15.	Related Party Transactions
16.	Property, Plant and Equipment
17.	Revenue from Contracts with Customers

GLOSSARY OF TERMS FOR NOTES

When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below.

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP	American Electric Power Company, Inc., an investor-owned electric public utility holding company which includes American Electric Power Company, Inc. (Parent) and majority-owned consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a consolidated VIE of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP East Companies	APCo, I&M, KGPCo, KPCo, OPCo and WPCo.
AEP System	American Electric Power System, an electric system, owned and operated by AEP subsidiaries.
AEP Wind Holdings, LLC	Acquired in April 2019 as Sempra Renewables LLC, develops, owns and operates, or holds interests in, wind generation facilities in the United States.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AEPTCo	AEP Transmission Company, LLC, a wholly-owned subsidiary of AEP Transmission Holdco, is an intermediate holding company that owns the State Transcos.
AFUDC	Allowance for Equity Funds Used During Construction.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary. APCo engages in the generation, transmission and distribution of electric power to retail customers in the southwestern portion of Virginia and southern West Virginia.
ARO	Asset Retirement Obligations.
CAMT	Corporate Alternative Minimum Tax.
CCR	Coal Combustion Residual.
CODM	Chief Operating Decision Maker.
Cook Plant	Donald C. Cook Nuclear Plant, a two-unit, 2,296 MW nuclear plant owned by I&M.
CWIP	Construction Work in Progress.
DCC Fuel	DCC Fuel XIV, DCC Fuel XV, DCC Fuel XVI, DCC Fuel XVII and DCC Fuel XVIII, DCC Fuel XIX and DCC Fuel XX consolidated VIEs formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M.
DOE	U. S. Department of Energy.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company and consolidated VIE of AEP.
Excess ADIT	Excess accumulated deferred income taxes.
FAC	Fuel Adjustment Clause.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary. I&M engages in the generation, transmission and distribution of electric power to retail customers in northern and eastern Indiana and southwestern Michigan.
IRA	On August 16, 2022 President Biden signed into law legislation commonly referred to as the “Inflation Reduction Act” (IRA).
IRS	Internal Revenue Service.
ITC	Investment Tax Credit.

Term	Meaning
IURC	Indiana Utility Regulatory Commission.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary. KGPCo provides electric service to retail customers in Kingsport, Tennessee and eight neighboring communities in northeastern Tennessee.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary. KPCo engages in the generation, transmission and distribution of electric power to retail customers in eastern Kentucky.
KWh	Kilowatt-hour.
MPSC	Michigan Public Service Commission.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatt-hour.
NOL	Net operating losses.
NOLC	Net operating loss carryforward.
NO_x	Nitrogen oxide.
NRC	Nuclear Regulatory Commission.
OATT	Open Access Transmission Tariff.
OPCo	Ohio Power Company, an AEP electric utility subsidiary. OPCo engages in the transmission and distribution of electric power to retail customers in Ohio.
OPEB	Other Postretirement Benefits.
OTC	Over-the-counter.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.
Parent	American Electric Power Company, Inc., the equity owner of AEP subsidiaries within the AEP consolidation.
PCA	Power Coordination Agreement among APCo, I&M, KPCo and WPCo.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PLR	Private Letter Ruling.
PPA	Purchase Power Agreement.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary. PSO engages in the generation, transmission and distribution of electric power to retail customers in eastern and southwestern Oklahoma.
PTC	Production Tax Credit.
Risk Management Contracts	Trading and non-trading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generation plant, jointly-owned by AEGCo and I&M, consisting of two 1,310 MW coal-fired generating units near Rockport, Indiana.
ROE	Return on Equity.
RPM	Reliability Pricing Model.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
Sempra Renewables LLC	Sempra Renewables LLC, acquired in April 2019 (subsequently renamed as AEP Wind Holdings LLC), consists of 724 MWs of wind generation and battery assets in the United States.
SO_2	Sulfur dioxide.
SPP	Southwest Power Pool regional transmission organization.
SNF	Spent Nuclear Fuel.
TA	Transmission Agreement, effective November 2010, among APCo, I&M, KGPCo, KPCo, OPCo and WPCo with AEPSC as agent.
Tax Reform	On December 22, 2017, President Trump signed into law legislation referred to as the “Tax Cuts and Jobs Act” (the TCJA). The TCJA includes significant changes to the Internal Revenue Code of 1986, including a reduction in the corporate federal income tax rate from 35% to 21% effective January 1, 2018.

Term	Meaning
UPA	Unit Power Agreement.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
VIE	Variable Interest Entity.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary. WPCo provides electric service to retail customers in northern West Virginia.

1.
ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES
ORGANIZATION

As a public utility, I&M engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to approximately 617,000 retail customers in its service territory in northern and eastern Indiana and southwestern Michigan. I&M sells power at wholesale to municipalities and electric cooperatives. I&M's River Transportation Division provides barging services to affiliates and nonaffiliated companies. The revenues from barging represent the majority of other revenues.

To minimize the credit requirements and operating constraints when operating within PJM, participating AEP companies, including I&M, agreed to a netting of certain payment obligations incurred by the participating AEP companies against certain balances due to such AEP companies and to hold PJM harmless from actions that any one or more AEP companies may take with respect to PJM.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

I&M's rates are regulated by the FERC, the IURC and the MPSC. The FERC also regulates I&M's affiliated transactions, including AEPSC intercompany service billings which are generally at cost, under the 2005 Public Utility Holding Company Act and the Federal Power Act. The FERC also has jurisdiction over certain issuances and acquisitions of securities of the public utility subsidiaries, the acquisition or sale of certain utility assets and mergers with another electric utility or holding company. The state regulatory commissions also regulate certain intercompany transactions under various orders and affiliate statutes. Both the FERC and state regulatory commissions are permitted to review and audit the relevant books and records of companies within a public utility holding company system.

The FERC regulates wholesale power markets and wholesale power transactions. I&M's wholesale power transactions are generally market-based. Wholesale power transactions are cost-based regulated when a cost-based contract is negotiated and filed with the FERC or the FERC determines that I&M has "market power" in the region where the transaction occurs. Wholesale power supply contracts have been entered into with various municipalities and cooperatives that are FERC-regulated, cost-based contracts. These contracts are generally formula rate mechanisms, which are trued-up to actual costs annually.

The IURC and the MPSC regulate all of the retail distribution operations and rates of I&M's retail public utility subsidiaries on a cost basis. They also regulate the retail generation/power supply operations and rates.

The FERC also regulates I&M's wholesale transmission operations and rates. Retail transmission rates are based upon the FERC OATT rate when retail rates are unbundled in connection with restructuring. Retail transmission rates are based on formula rates included in the PJM OATT that are cost-based and are unbundled in Michigan for I&M.

In addition, the FERC regulates the TA, which allocates shared system costs and revenues among the utility subsidiaries that are parties to the agreement. The FERC also regulates the PCA. See Note 15 - Related Party Transactions for additional information.
Basis of Accounting

I&M's accounting is subject to the requirements of the IURC, the MPSC and the FERC. The financial statements have been prepared in accordance with the Uniform System of Accounts prescribed by the FERC. The principal differences from GAAP include:

- Accounting for subsidiaries on an equity basis.
- The classification of deferred fuel as noncurrent rather than current.
- The requirement to report deferred tax assets and liabilities separately rather than as a single amount.
- The classification of accrued taxes as a single amount rather than as assets and liabilities.
- The exclusion of current maturities of long-term debt from current liabilities.
- The classification of accrued non-ARO asset removal costs as accumulated depreciation rather than regulatory liabilities.
- The classification of finance lease payments as operating activities instead of financing activities.
- The classification of gains/losses from disposition of allowances as utility operating expenses rather than as operating revenues.
- The classification of PJM hourly activity for physical transactions as purchases and sales instead of net sales.
- The classification of an accrued provision for potential refund as other noncurrent liability rather than a current liability.
- The classification of regulatory assets and liabilities related to the accounting guidance for "Accounting for Income Taxes" as separate assets and liabilities rather than as a single amount.
- The presentation of finance leased assets and their associated accumulated amortization as a single amount instead of as separate amounts.
- The classification of factored accounts receivable expense as a nonoperating expense instead of as an operating expense.
- The presentation of over/under fuel recovery in revenue rather than as a component of operating expense.
- The classification of certain nonoperating revenues as miscellaneous nonoperating income instead of as operating revenue.
- The classification of certain nonoperating expenses as miscellaneous nonoperating expense instead of as operating expense.
- The separate classification of income tax expense for operating and nonoperating activities instead of as a single income tax expense.
- The classification of DCC Fuel as a capital lease rather than consolidating in accordance with the accounting guidance for "Variable Interest Entities."
- The classification of unamortized loss on reacquired debt in deferred debits rather than in regulatory assets.
- The classification of accumulated deferred investment tax credits in deferred credits rather than in regulatory liabilities and deferred investment tax credits.
- The classification of plant impairment in utility plant adjustments rather than in property, plant and equipment.
- The classification of plant impairment in utility plant adjustments rather than in property, plant and equipment - accumulated depreciation and amortization.
- The classification of certain other assets and liabilities as current instead of noncurrent.
- The classification of certain other assets and liabilities as noncurrent instead of current.
- The classification of debt issuance costs as noncurrent assets instead of noncurrent liabilities.
- The classification of unrecovered plant costs as accumulated depreciation instead of regulatory assets.
- The classification of rents receivable as rents receivable instead of customer accounts receivable.
- The classification of Non-Service Cost Components of Net Periodic Benefit Cost as Operating Expense instead of Other Income (Expense).
- The classification of operating lease assets as Utility Plant rather than as a noncurrent asset.
- The classification of operating lease assets as Other Property and Investments rather than as noncurrent assets.
- The presentation of obligations under finance and operating leases as a single amount in Obligations Under Capital Leases rather than as separate items.
- The classification of certain expenses in operating income rather than operating expenses.
- The classification of interest on regulated finance leases as operating expense instead of Other Income (Expense).
- The classification of cloud computing implementation costs as Utility Plant rather than as a noncurrent asset.
- The classification of cloud computing implementation costs as Other Property and Investments rather than as a noncurrent asset.
- The classification of certain plant balances as nonutility property rather than as utility property.
- The presentation of certain property balances on a net basis in gross property rather than a split between gross property and accumulated depreciation.
- The classification of the amortization of excess SO^2 allowances as current and accrued assets rather than noncurrent assets.
- The classification of the depreciation and amortization of Rockport Unit 2 in accumulated depreciation and amortization - nonutility rather than accumulated depreciation and amortization - utility.

Accounting for the Effects of Cost-Based Regulation

I&M's financial statements reflect the actions of regulators that result in the recognition of certain revenues and expenses in different time periods than enterprises that are not rate-regulated. In accordance with accounting guidance for "Regulated Operations," regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred revenue reductions or refunds) are recorded to reflect the economic effects of regulation in the same accounting period by matching expenses with their recovery through regulated revenues and by matching income with its passage to customers in cost-based regulated rates.

Use of Estimates

The preparation of these financial statements requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. These estimates include, but are not limited to, inventory valuation, allowance for credit losses, long-lived asset impairment, unbilled electricity revenue, valuation of long-term energy contracts, the effects of regulation, long-lived asset recovery, storm costs, the effects of contingencies and certain assumptions made in accounting for pension and postretirement benefits. The estimates and assumptions used are based upon management's evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results could ultimately differ from those estimates.

Cash and Cash Equivalents

Cash and Cash Equivalents include Cash, Working Fund and Temporary Cash Investments on the balance sheets with original maturities of three months or less.
Supplementary Information

	2024	2023
For the Years Ended December 31,	**(in millions)**	
Cash was Paid for:		
Interest (Net of Capitalized Amounts)	$ 133.4	$ 123.9
Income Taxes (Net of Refunds)	24.0	108.9
Noncash Acquisitions Under Finance Leases	78.0	75.3
As of December 31,		
Construction Expenditures Included in Current and Accrued Liabilities	77.2	67.8
Nuclear Fuel Expenditures Included in Current and Accrued Liabilities	23.5	24.2

Special Deposits

Special Deposits include funds held by trustees primarily for margin deposits for risk management activities.

Inventory

Fossil fuel inventories and materials and supplies inventories are carried at average cost.

Accounts Receivable and Allowance for Credit Losses

Customer accounts receivable primarily include receivables from wholesale and retail energy customers, receivables from energy contract counterparties related to risk management activities and customer receivables primarily related to other revenue-generating activities.

Revenue is recognized over time as the performance obligations of delivering energy to customers are satisfied. To the extent that deliveries have occurred but a bill has not been issued, I&M accrues and recognizes, as Accrued Utility Revenues on the balance sheets, an estimate of the revenues for energy delivered since the last billing.

AEP Credit factors accounts receivable on a daily basis, excluding receivables from risk management activities, through purchase agreements with I&M. Under the securitization agreement, AEP Credit receives financing from bank conduits for a portion of its interests in the billed and unbilled receivables acquired from the affiliated utility subsidiaries. See "Securitized Accounts Receivable – AEP Credit" section of Note 14 for additional information.

Generally, AEP Credit records bad debt expense based upon a 12-month rolling average of bad debt write-offs in proportion to gross accounts receivable purchased from I&M. The assessment is performed separately for I&M which inherently contemplates any differences in geographical risk characteristics for the allowance for credit losses.

For customer accounts receivable relating to risk management activities, accounts receivable are reviewed for bad debt reserves at a specific counterparty level basis. For miscellaneous accounts receivable, bad debt expense is recorded based upon a 12-month rolling average of bad debt write-offs in proportion to gross accounts receivable, unless specifically identified.

In addition to these processes, management contemplates available current information, as well as any reasonable and supportable forecast information, to determine if allowances for credit losses should be further adjusted in accordance with the accounting guidance for "Credit Losses." Management's assessments contemplate expected losses over the life of the accounts receivable.

Concentrations of Credit Risk and Significant Customers

I&M does not have any significant customers that comprise 10% or more of its operating revenues for the years ended December 31 and Customer Accounts Receivable as of December 31, 2024 and 2023, respectively.

I&M monitors credit levels and the financial condition of its customers on a continuous basis to minimize credit risk. The regulatory commissions allow recovery in rates for a reasonable level of bad debt costs. Management believes adequate provisions for credit loss have been made in the accompanying financial statements.

Renewable Energy Credits

I&M records renewable energy credits (RECs) at cost. I&M follows the inventory model for these RECs. RECs are reported in Miscellaneous Current and Accrued Assets on the balance sheets. The purchases and sales of RECs are reported in the Operating Activities section of the statements of cash flows. RECs that are consumed to meet applicable state renewable portfolio standards are recorded in Operation Expenses at an average cost on the statements of income. The net margin on sales of RECs affects the determination of deferred fuel and REC costs.

Property, Plant and Equipment

Electric utility property, plant and equipment for rate-regulated operations are stated at original cost. Additions, major replacements and betterments are added to the plant accounts. Under the group composite method of depreciation, continuous interim routine replacements of items such as boiler tubes, pumps, motors, etc. result in original cost retirements, less salvage, being charged to accumulated depreciation. The group composite method of depreciation assumes that on average, asset components are retired at the end of their useful lives and thus there is no gain or loss. The equipment in each primary electric plant account is identified as a separate group. The depreciation rates that are established take into account the past history of interim capital replacements and the amount of removal cost incurred and salvage received. These rates and the related lives are subject to periodic review.

Removal costs accrued are charged to accumulated depreciation. The costs of labor, materials and overhead incurred to operate and maintain plant and equipment are included in operating expenses.

Nuclear fuel, including nuclear fuel in the fabrication phase, is included in Net Nuclear Fuel on the balance sheets.

Long-lived assets are required to be tested for impairment when it is determined that the carrying value of the assets may no longer be recoverable or when the assets meet the held-for-sale criteria under the accounting guidance for "Impairment or Disposal of Long-Lived Assets." When it becomes probable that an asset in-service or an asset under construction will be abandoned and regulatory cost recovery has been disallowed or is not probable, the cost of that asset shall be written down to its then current estimated fair value, with the change charged to expense, and the asset is removed from plant-in-service or CWIP.

The fair value of an asset is the amount at which that asset could be bought or sold in a current transaction between willing parties, as opposed to a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, fair value is estimated using various internal and external valuation methods including cash flow analysis and appraisals.

Investment in Subsidiary Companies

I&M has two wholly-owned subsidiaries, Blackhawk Coal Company and Price River Coal Company that were formerly engaged in coal-mining operations. Blackhawk Coal Company currently leases and subleases portions of its Utah coal rights and land to nonaffiliated companies. Price River Coal Company which owns no land or mineral rights is inactive. Investment in the net assets of the two wholly-owned subsidiaries is carried at cost plus equity in their undistributed earnings since acquisition.

Allowance for Funds Used During Construction

AFUDC represents the estimated cost of borrowed and equity funds used to finance construction projects that is capitalized and recovered through depreciation over the service life of regulated electric utility plant.

Asset Retirement Obligations

I&M records ARO in accordance with the accounting guidance for "Asset Retirement and Environmental Obligations" for legal obligations for asbestos removal, the retirement of certain ash disposal facilities and the decommissioning of the Cook Plant. I&M also records AROs related to the Federal EPA's revised CCR Rule. For operating facilities, the present value of the liability is added to the cost of the associated asset and depreciated over the remaining life of the asset. For retired facilities, the present value of the liability is expensed, and where future recovery through rates is probable, the present value of the liability is subsequently deferred as a regulatory asset.

AROs are computed as the present value of the estimated costs associated with the future retirement of an asset and are recorded in the period in which the liability is incurred. Estimates of the timing and amounts of future cash outlays are based on projections of when and how the assets will be decommissioned and the liabilities will be remediated as well as the inflation rate and discount rate, which may change significantly over time. The estimated costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. I&M has identified, but not recognized, ARO liabilities related to electric transmission and distribution assets as a result of certain easements on property on which assets are owned. Generally, such easements are perpetual and require only the retirement and removal of assets upon the cessation of the property's use. The retirement obligation is not estimable for such easements since I&M plans to use their facilities indefinitely. The retirement obligation would only be recognized if and when I&M abandons or ceases the use of specific easements, which is not expected.

Valuation of Nonderivative Financial Instruments

The book values of Cash, Special Deposits, Working Fund, Notes Receivable from Associated Companies, Notes Payable to Associated Companies, accounts receivable and accounts payable approximate fair value because of the short-term maturity of these instruments.

Fair Value Measurements of Assets and Liabilities

The accounting guidance for "Fair Value Measurements and Disclosures" establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. When quoted market prices are not available, pricing may be completed using comparable securities, dealer values, operating data and general market conditions to determine fair value. Valuation models utilize various inputs such as commodity, interest rate and, to a lesser degree, volatility and credit that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability.

For commercial activities, exchange-traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified as Level 1. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, as well as exchange-traded derivatives where there is insufficient market liquidity to warrant inclusion in Level 1. Management verifies price curves using these broker quotes and classifies these fair values within Level 2 when substantially all of the fair value can be corroborated. Management typically obtains multiple broker quotes, which are nonbinding in nature but are based on recent trades in the marketplace. When multiple broker quotes are obtained, the quoted bid and ask prices are averaged. In certain circumstances, a broker quote may be discarded if it is a clear outlier. Management uses a historical correlation analysis between the broker quoted location and the illiquid locations. If the points are highly correlated, these locations are included within Level 2 as well. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. Illiquid transactions, complex structured transactions, FTRs and counterparty credit risk may require nonmarket-based inputs. Some of these inputs may be internally developed or extrapolated and utilized to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized as Level 3. The main driver of contracts being classified as Level 3 is the inability to substantiate energy price curves in the market. A portion of the Level 3 instruments have been economically hedged which limits potential earnings volatility.

AEP utilizes its trustee's external pricing service to estimate the fair value of the underlying investments held in the benefit plan and nuclear trusts. AEP's investment managers review and validate the prices utilized by the trustee to determine fair value. AEP's management performs its own valuation testing to verify the fair values of the securities. AEP receives audit reports of the trustee's operating controls and valuation processes.

Assets in the benefits and nuclear trusts are classified using the following methods. Equities are classified as Level 1 holdings if they are actively traded on exchanges. Items classified as Level 1 are investments in money market funds, fixed income and equity mutual funds and equity securities. They are valued based on observable inputs, primarily unadjusted quoted prices in active markets for identical assets. Items classified as Level 2 are primarily investments in individual fixed income securities. Fixed income securities generally do not trade on exchanges and do not have an official closing price but their valuation inputs are based on observable market data. Pricing vendors calculate bond valuations using financial models and matrices. The models use observable inputs including yields on benchmark securities, quotes by securities brokers, rating agency actions, discounts or premiums on securities compared to par prices, changes in yields for U.S. Treasury securities, corporate actions by bond issuers, prepayment schedules and histories, economic events and, for certain securities, adjustments to yields to reflect changes in the rate of inflation. Other securities with model-derived valuation inputs that are observable are also classified as Level 2 investments. Investments with unobservable valuation inputs are classified as Level 3 investments. Investments classified as Other are valued using Net Asset Value as a practical expedient. Items classified as Other are primarily cash equivalent funds, common collective trusts, commingled funds, structured products, private equity, real estate and infrastructure investments. These investments do not have a readily determinable fair value or they contain redemption restrictions which may include the right to suspend redemptions under certain circumstances. Redemption restrictions may also prevent certain investments from being redeemed at the reporting date for the underlying value.

Deferred Fuel Costs

The cost of purchased electricity, fuel and related emission allowances and emission control chemicals/consumables is charged to Operation Expenses when the fuel is burned or the allowance or consumable is utilized. The cost of fuel also includes the cost of nuclear fuel burned which is computed primarily using the units-of-production method. Fuel cost over-recoveries (the excess of fuel-related revenues over applicable fuel costs incurred) are generally deferred as regulatory liabilities and under-recoveries (the excess of applicable fuel costs incurred over fuel-related revenues) are generally deferred as regulatory assets. These deferrals are incorporated into the development of future fuel rates billed to or refunded to customers. The amount of an over-recovery or under-recovery can also be affected by actions of the IURC and the MPSC. On a routine basis, the IURC and the MPSC review and/or audit I&M's fuel procurement policies and practices, the fuel cost calculations and FAC deferrals. FAC deferrals are adjusted when costs are no longer probable of recovery or when refunds of fuel reserves are probable. I&M, shares the majority of its Off-system Sales margins to customers either through an active FAC or other rate mechanisms. Where the FAC or Off-system Sales sharing mechanism is capped, frozen, non-existent or not applicable to merchant operations, changes in fuel costs or sharing of off-system sales impact earnings.

Revenue Recognition

Regulatory Accounting

I&M's financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. Regulatory assets (deferred expenses or alternative revenues recognized in accordance with the guidance for "Regulated Operations") and regulatory liabilities (deferred revenue reductions or refunds) are recorded to reflect the economic effects of regulation in the same accounting period by matching expenses with their recovery through regulated revenues and by matching revenue with its passage to customers in cost-based regulated rates.

When regulatory assets are probable of recovery through regulated rates, assets are recorded on the balance sheets. Regulatory assets are reviewed for probability of recovery at each balance sheet date or whenever new events occur. Examples of new events include the issuance of a regulatory commission order or passage of new legislation. If it is determined that recovery of a regulatory asset is no longer probable, the regulatory asset is derecognized as a charge against income.

Retail and Wholesale Supply and Delivery of Electricity

I&M recognizes revenues from customers for retail and wholesale electricity sales and electricity transmission and distribution delivery services. I&M recognizes such revenues on the statements of income as the performance obligations of delivering energy to customers are satisfied. Recognized revenues include both billed and unbilled amounts.

Wholesale transmission revenue is based on FERC-approved formula rate filings made for each calendar year using estimated costs. Revenues initially recognized per the annual rate filing are compared to actual costs, resulting in the subsequent recognition of an over or under-recovered amount, with interest, that is refunded or recovered, respectively, in a future year's rates. These annual true-ups meet the definition of alternative revenues in accordance with the accounting guidance for "Regulated Operations". An estimated annual true-up is recorded by I&M in the fourth quarter of each calendar year and a final annual true-up is recognized by I&M in the second quarter of each calendar year following the filing of annual FERC reports. Any portion of the true-ups applicable to an affiliated company is recorded as Accounts Receivable from Associated Companies or Accounts Payable to Associated Companies on the balance sheets. Any portion of the true-ups applicable to third-parties is recorded as regulatory assets or regulatory liabilities on the balance sheets. See Note 17 - Revenue from Contracts with Customers for additional information.

Gross versus Net Presentation of Certain Electricity Supply and Delivery Activities

Most of the power produced at the generation plants is sold to PJM. I&M also purchases power from PJM to supply power to customers. Generally, these power sales and purchases are reported on a net basis as revenues on the statements of income. However, purchases of power in excess of sales to PJM, on an hourly net basis, used to serve retail load are recorded gross as Operation Expenses on the statements of income.

Physical energy purchases arising from non-derivative contracts are accounted for on a gross basis in Operation Expenses on the statements of income. Energy purchases arising from non-trading derivative contracts are recorded based on the transaction's facts and circumstances. Purchases under non-trading derivatives used to serve accrual based obligations are recorded in Operation Expenses on the statements of income. All other non-trading derivative purchases are recorded net in revenues.

In general, I&M records expenses when purchased electricity is received and when expenses are incurred. I&M defers unrealized MTM amounts as regulatory assets (for losses) and regulatory liabilities (for gains).

Energy Marketing and Risk Management Activities

I&M engages in power, capacity and, to a lesser extent, natural gas marketing as a major power producer and participant in electricity and natural gas markets. I&M also engages in power, capacity, coal, natural gas and, to a lesser extent, heating oil, gasoline and other commodity risk management activities focused on markets where the AEP System owns assets and on adjacent markets. These activities include the purchase-and-sale of energy under forward contracts at fixed and variable prices. These contracts include physical transactions, exchange-traded futures, and to a lesser extent, OTC swaps and options. Certain energy marketing and risk management transactions are with RTOs.

I&M recognizes revenues from marketing and risk management transactions that are not derivatives as the performance obligation of delivering the commodity is satisfied. Expenses from marketing and risk management transactions that are not derivatives are also recognized upon delivery of the commodity.

I&M uses MTM accounting for marketing and risk management transactions that are derivatives unless the derivative is designated in a qualifying cash flow hedge relationship or elected normal under the normal purchase normal sale election. Unrealized MTM gains and losses are included on the balance sheets as Derivative Instrument Assets or Liabilities, as appropriate, and on the statements of income in Operating Revenues. I&M includes realized gains and losses on marketing and risk management transactions in revenue or expense based on the transaction's facts and circumstances. The unrealized MTM amounts and some realized gains and losses are deferred as regulatory assets (for losses) and regulatory liabilities (for gains).

Certain qualifying marketing and risk management derivatives transactions are designated as hedges of variability in future cash flows as a result of forecasted transactions (cash flow hedge). In the event I&M designates a cash flow hedge, the cash flow hedge's gain or loss is initially recorded as a component of AOCI. When the forecasted transaction is realized and affects
net income, I&M subsequently reclassifies the gain or loss on the hedge from AOCI into revenues or expenses within the same financial statement line item as the forecasted transaction on their statements of income. See "Accounting for Cash Flow Hedging Strategies" section of Note 9 for additional information.

Levelization of Nuclear Refueling Outage Costs

In accordance with regulatory orders, I&M defers incremental operation and maintenance costs associated with periodic refueling outages at its Cook Plant and amortizes the costs over approximately 18 months, beginning with the month following the start of each unit's refueling outage and lasting until the end of the month in which the same unit's next scheduled refueling outage begins.

Maintenance

I&M expenses maintenance costs as incurred. If it becomes probable that I&M will recover specifically-incurred costs through future rates, a regulatory asset is established to match the expensing of those maintenance costs with its recovery in cost-based regulated revenues. I&M defers costs above the level included in base rates and amortizes those deferrals commensurate with recovery through rate riders.

Income Taxes and Investment Tax Credits

I&M uses the liability method of accounting for income taxes. Under the liability method, deferred income taxes are provided for all temporary differences between the book and tax basis of assets and liabilities which will result in a future tax consequence. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which the temporary differences are expected to be recovered or settled.

When the flow-through method of accounting for temporary differences is required by a regulator to be reflected in regulated revenues (that is, when deferred taxes are not included in the cost-of-service for determining regulated rates for electricity), deferred income taxes are recorded and related regulatory assets and liabilities are established to match the regulated revenues and tax expense.

I&M applies the deferral methodology for the recognition of ITCs. Deferred ITCs are amortized to income tax expense over the life of the asset that generated the credit. Amortization of deferred ITCs begins when the asset is placed in-service, except where regulatory commissions reflect ITCs in the rate-making process, then amortization begins when the utility is able to utilize the ITC on a stand-alone basis.

Transferable tax credits established by the IRA are accounted for in accordance with the accounting guidance for "Income Taxes" by I&M. Proceeds from sales of transferable tax credits are included as a component of Operating Activities on the statement of cash flows and presented as gross within the Supplementary Cash Flow Information.

I&M accounts for uncertain tax positions in accordance with the accounting guidance for "Income Taxes." I&M classifies interest expense or income related to uncertain tax positions as interest expense or income as appropriate and classifies penalties as Penalties on the statements of income.

I&M joins in the filing of a consolidated federal income tax return. The benefit of current tax loss of the parent company (Parent Company Loss Benefit) to the AEP System subsidiaries is accounted for as an allocation through equity. The consolidated NOL of the AEP System is allocated to each company in the consolidated group with taxable loss. With the exception of the allocation of the consolidated AEP System NOL, Parent Company Loss Benefit and tax credits, the method of allocation reflects a separate return result for each company in the consolidated group.

Excise Taxes

As an agent for some state and local governments, I&M collects from customers certain excise taxes levied by those state or local governments on customers. I&M does not record these taxes as revenue or expense.

Debt

Gains and losses from the reacquisition of debt used to finance regulated electric utility assets are deferred and amortized over the remaining term of the reacquired debt in accordance with their rate-making treatment unless the debt is refinanced. If the reacquired debt associated with the regulated business is refinanced, the reacquisition costs attributable to the portions of the business that are subject to cost-based regulatory accounting are generally deferred and amortized over the term of the replacement debt consistent with its recovery in rates.

Debt discount or premium and debt issuance expenses are deferred and amortized generally utilizing the straight-line method over the term of the related debt. The straight-line method approximates the effective interest method and is consistent with the treatment in rates for regulated operations.

Pension and OPEB Plans

I&M participates in an AEPSC sponsored qualified pension plan and two unfunded nonqualified pension plans. Substantially all I&M's employees are covered by the qualified plan or both the qualified and a nonqualified pension plan. I&M also participates in OPEB plans sponsored by AEPSC to provide health and life insurance benefits for retired employees. I&M is allocated a proportionate share of benefit costs and account for their participation in these plans as multiple-employer plans. See Note 7 - Benefit Plans for additional information including significant accounting policies associated with the plans.

Investments Held in Trust for Future Liabilities

AEP has several trust funds with significant investments intended to provide for future payments of pension and OPEB benefits, nuclear decommissioning and SNF disposal. All of the trust funds' investments are diversified and managed in compliance with all laws and regulations. The investment strategy for the trust funds is to use a diversified portfolio of investments to achieve an acceptable rate of return while managing the investment risk of the assets relative to the associated liabilities. To minimize investment risk, the trust funds are broadly diversified among classes of assets, investment strategies and investment managers. Management regularly reviews the actual asset allocations and periodically rebalances the investments to targeted allocations when appropriate. Investment policies and guidelines allow investment managers in approved strategies to use financial derivatives to obtain or manage market exposures and to hedge assets and liabilities. The investments are reported at fair value under the "Fair Value Measurements and Disclosures" accounting guidance.

Benefit Plans

All benefit plan assets are invested in accordance with each plan's investment policy. The investment policy outlines the investment objectives, strategies and target asset allocations by plan.

The investment philosophies for AEP's benefit plans support the allocation of assets to minimize risks and optimize net returns. Strategies used include:

- Maintaining a long-term investment horizon.
- Diversifying assets to help control volatility of returns at acceptable levels.
- Managing fees, transaction costs and tax liabilities to maximize investment earnings.
- Using active management of investments where appropriate risk/return opportunities exist.
- Keeping portfolio structure style-neutral to limit volatility compared to applicable benchmarks.

- Using alternative asset classes such as real estate and private equity to maximize return and provide additional portfolio diversification.

The objective of the investment policy for the pension fund is to maintain the funded status of the plan while providing for growth in the plan assets to offset the growth in the plan liabilities. The current target asset allocations are as follows:

Pension Plan Assets	Target
Equity	35 %
Fixed Income	49 %
Other Investments	15 %
Cash and Cash Equivalents	1 %

OPEB Plans Assets	Target
Equity	67 %
Fixed Income	32 %
Cash and Cash Equivalents	1 %

The investment policy for each benefit plan contains various investment limitations. The investment policies establish concentration limits for securities and prohibit the purchase of securities issued by AEP (with the exception of proportionate and immaterial holdings of AEP securities in passive index strategies or certain commingled funds). However, the investment policies do not preclude the benefit trust funds from receiving contributions in the form of AEP securities, provided that the AEP securities acquired by each plan may not exceed the limitations imposed by law.

For equity investments, the concentration limits are generally as follows:

- No security in excess of 5% of the outstanding class of equity of any one company.
- Cash equivalents must be less than 10% of an investment manager's equity portfolio.
- No securities may be bought or sold on margin or other use of leverage.

For fixed income investments, each investment manager's portfolio is compared to investment grade, diversified benchmark indices.

A portion of the pension assets is invested in real estate funds to provide diversification, add return and hedge against inflation. Real estate properties are illiquid, difficult to value and not actively traded. The pension plan uses external real estate investment managers to invest in commingled funds that hold real estate properties. To mitigate investment risk in the real estate portfolio, commingled real estate funds are used to ensure that holdings are diversified by region, property type and risk classification. Real estate holdings include core, value-added and opportunistic classifications.

A portion of the pension assets is invested in private equity. Private equity investments add return and provide diversification and typically require a long-term time horizon to evaluate investment performance. Private equity is classified as an alternative investment because it is illiquid, difficult to value and not actively traded. The pension plan uses limited partnerships to invest across the private equity investment spectrum. The private equity holdings are with multiple general partners who help monitor the investments and provide investment selection expertise. The holdings are currently comprised of venture capital, buyout and hybrid debt and equity investments.

AEP participates in a securities lending program with BNY Mellon to provide incremental income on idle assets and to provide income to offset custody fees and other administrative expenses. AEP lends securities to borrowers approved by BNY Mellon in exchange for collateral. All loans are collateralized by at least 102% of the loaned asset's market value and the collateral is invested. The difference between the rebate owed to the borrower and the collateral rate of return determines the earnings on the loaned security. The securities lending program's objective is to provide modest incremental income with a limited increase in risk. As of December 31, 2024 and 2023, the fair value of securities on loan as part of the program was $60 million and $62 million, respectively. Cash and securities obtained as collateral exceeded the fair value of the securities loaned as of December 31, 2024 and 2023.

Trust owned life insurance (TOLI) underwritten by The Prudential Insurance Company is held in the OPEB plan trusts. The strategy for holding life insurance contracts in the taxable Voluntary Employees' Beneficiary Association trust is to minimize taxes paid on the asset growth in the trust. Earnings on plan assets are tax-deferred within the TOLI contract and can be tax-
free if held until claims are paid. Life insurance proceeds remain in the trust and are used to fund future retiree medical benefit liabilities. With consideration to other investments held in the trust, the cash value of the TOLI contracts is invested in two diversified funds. A portion is invested in a commingled fund with underlying investments in stocks that are actively traded on major international equity exchanges. The other portion of the TOLI cash value is invested in a diversified, commingled fixed income fund with underlying investments in government bonds, corporate bonds and asset-backed securities.

Cash and cash equivalents are held in each trust to provide liquidity and meet short-term cash needs. Cash equivalent funds are used to provide diversification and preserve principal. The underlying holdings in the cash funds are investment grade money market instruments including commercial paper, certificates of deposit, treasury bills and other types of investment grade short-term debt securities.

Nuclear Trust Funds

Nuclear decommissioning and SNF trust funds represent funds that regulatory commissions allow I&M to collect through rates to fund future decommissioning and SNF disposal liabilities. By rules or orders, the IURC, the MPSC and the FERC established investment limitations and general risk management guidelines. In general, limitations include:

- Acceptable investments (rated investment grade or above when purchased).
- Maximum percentage invested in a specific type of investment.
- Prohibition of investment in obligations of AEP, I&M or their affiliates.
- Withdrawals permitted only for payment of decommissioning costs and trust expenses.

I&M maintains trust funds for each regulatory jurisdiction. Regulatory approval is required to withdraw decommissioning funds. These funds are managed by an external investment manager that must comply with the guidelines and rules of the applicable regulatory authorities. The trust assets are invested to optimize the net of tax earnings of the trust giving consideration to liquidity, risk, diversification and other prudent investment objectives.

I&M records securities held in these trust funds in Other Special Funds on its balance sheets. I&M records these securities at fair value. I&M classifies debt securities in the trust funds as available-for-sale due to their long-term purpose.

Other-than-temporary impairments for investments in debt securities are considered realized losses as a result of securities being managed by an external investment management firm. The external investment management firm makes specific investment decisions regarding the debt and equity investments held in these trusts and generally intends to sell debt securities in an unrealized loss position as part of a tax optimization strategy. Impairments reduce the cost basis of the securities which will affect any future unrealized gain or realized gain or loss due to the adjusted cost of investment. I&M records unrealized gains, unrealized losses and other-than-temporary impairments from securities in these trust funds as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the SNF disposal trust funds in accordance with their treatment in rates. Consequently, changes in fair value of trust assets do not affect earnings or AOCI. See the "Nuclear Contingencies" section of Note 6 for additional discussion of nuclear matters. See "Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal" section of Note 10 for disclosure of the fair value of assets within the trusts.

Comprehensive Income (Loss)

Comprehensive income (loss) is defined as the change in equity (net assets) of a business enterprise during a period from transactions and other events and circumstances from non-owner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners.

Subsequent Events

Management has evaluated the impact of events occurring after December 31, 2024 through February 13, 2025, the date that AEP's Form 10-K was issued, and has updated such evaluation for disclosure purposes through April 8, 2025. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.

2. NEW ACCOUNTING STANDARDS

During the FASB's standard-setting process and upon issuance of final standards, management reviews the new accounting literature to determine its relevance, if any, to I&M's business. The following standards will impact I&M's financial statements.

ASU 2023-07 "Improvements to Reportable Segment Disclosures" (ASU 2023-07)

In November 2023, the FASB issued ASU 2023-07, to address investors' observations that there is limited information disclosed about segment expenses and to better understand expense categories and amounts included in segment profit or loss. The new standard requires annual and interim disclosure of (a) the categories and amounts of significant segment expenses (determined by management using both qualitative and quantitative factors) that are regularly provided to the CODM and included within each reported measure of segment profit or loss, (b) the amounts and a qualitative description of "other segment items", defined as the difference between reported segment revenues less the significant segment expenses and each reported measure of segment profit or loss disclosed, (c) reportable segment profit or loss and assets that are currently only required annually, (d) the CODM's title and position, and an explanation of how the CODM uses the reported measure(s) of segment profit or loss in assessing segment performance and deciding how to allocate resources and (e) a requirement that entities with a single reportable segment provide all disclosures required by ASU 2023-07 and all existing segment disclosures in Topic 280. Additionally, this new standard allows disclosure of one or more of additional profit or loss measures if the CODM uses more than one measure provided that at least one of the disclosed measures is determined in a manner "most consistent with the measurement principles under GAAP". If multiple measures are presented, additional disclosure is required about how the CODM uses each measure to assess performance and decide how to allocate resources.

Management adopted ASU 2023-07 and its related implementation guidance effective January 1, 2024 for the annual reporting period and applied the amendments retrospectively to all prior periods presented in the consolidated financial statements. The amendments for interim periods will be adopted in our fiscal year beginning on January 1, 2025. The adoption of the new standard did not impact the results of operations, statements of financial position or cash flows.

ASU 2023-09 "Improvements to Income Tax Disclosures" (ASU 2023-09)

In December 2023, the FASB issued ASU 2023-09, to address investors' suggested enhancements to (a) better understand an entity's exposure to potential changes in jurisdictional tax legislation and the ensuing risks and opportunities, (b) assess income tax information that affects cash flow forecasts and capital allocation decisions and (c) identify potential opportunities to increase future cash flows.

The new standard requires an annual rate reconciliation disclosure of the following categories regardless of materiality: state and local income tax, net of federal income tax effect, foreign tax effects, effect of changes in tax laws or rates enacted in the current period, effect of cross-border tax laws, tax credits, changes in valuation allowances, nontaxable or nondeductible items and changes in unrecognized tax benefits.

The new standard also requires an annual disclosure of the amount of income taxes paid (net of refunds received) disaggregated by federal, state and foreign taxes and by individual jurisdictions that are equal to or greater than 5 percent of total income taxes paid. Disclosure of income (loss) from continuing operations before income tax expense (benefit) disaggregated between domestic and foreign jurisdictions and income tax expense (benefit) from continuing operations disaggregated by federal, state and foreign jurisdictions is required.

The new standard removes the requirement to disclose the cumulative amount of each type of temporary difference when a deferred tax liability is not recognized because of the exceptions to comprehensive recognition of deferred taxes related to subsidiaries and corporate joint ventures.

The amendments in the new standard may be applied on either a prospective or retrospective basis for public business entities for fiscal years beginning after December 15, 2024 with early adoption permitted. Management has concluded to adopt the amendments to this standard prospectively beginning on January 1, 2025.

ASU 2024-03 "Income Statement-Reporting Comprehensive Income-Expense Disaggregation Disclosures" (ASU 2024-03)

In November 2024, the FASB issued ASU 2024-03, the intent of which is to improve financial reporting and respond to investor input by requiring public business entities to disclose additional information about certain expenses in the notes to financial statements in interim and annual reporting periods. Among other provisions, the new standard requires disclosure of disaggregated amounts for expenses such as employee compensation, depreciation, and intangible asset amortization included in each expense caption presented on the face of the income statement. Public business entities are required to include certain amounts that are already required to be disclosed under GAAP in the same disclosure as the other disaggregation requirements as well as a qualitative description of any amounts remaining in relevant expense captions that are not separately disaggregated quantitatively. The new standard also requires disclosure of the total amount of selling expenses and, in annual reporting periods, an entity's definition of selling expenses. An entity is not precluded from providing additional voluntary disclosures that may provide investors with additional decision-useful information.

The amendments in the new standard are effective for annual reporting periods beginning after December 15, 2026, and interim reporting periods beginning after December 15, 2027, with early adoption permitted. The amendments in the new standard should be applied either prospectively to financial statements issued for reporting periods after the effective date or retrospectively to any or all prior periods presented in the financial statements. Management is evaluating the new standard and has not yet determined when, or the method by which, I&M will adopt its amendments.

3. COMPREHENSIVE INCOME

I&M's balance and activity in AOCI was not material for the years ended December 31, 2024 and December 31, 2023.

4. RATE MATTERS

I&M is involved in rate and regulatory proceedings at the FERC, the IURC and the MPSC. Rate matters can have a material impact on net income, cash flows and possibly financial condition. I&M's recent significant rate orders and pending rate filings are addressed in this note.

2023 Michigan Power Supply Cost Recovery (PSCR) Reconciliation

In March 2024, I&M submitted its 2023 PSCR Reconciliation to the MPSC. In October 2024, MPSC staff and intervenors submitted testimony recommending PSCR cost disallowances associated with the OVEC Inter-Company Power Agreement and the Rockport UPA with AEGCo ranging from $3 million to $15 million. A hearing was held in December 2024. If any PSCR costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

2023 Indiana Base Rate Case

In August 2023, I&M filed a request with the IURC for a $116 million annual increase in Indiana base rates based upon a 2024 forecasted test year, a proposed 10.5% ROE and a proposed capital structure of 48.8% debt and 51.2% common equity. I&M proposed that the annual increase in base rates be implemented in two steps, with the first increase effective in mid-2024, following an IURC order, and the second increase effective in January 2025. The proposed annual increase includes, but is not limited to, a $41 million increase related to depreciation expense, driven by increased depreciation rates and increased capital investments, and a $15 million increase related to storm expenses. I&M's Indiana base case filing requested recovery of certain historical period regulatory asset balances and proposed deferral accounting for certain future investments and tax-related issues, including CAMT expense and PTCs related to the Cook Plant.

In December 2023, I&M and intervenors reached a settlement agreement that was submitted to the IURC recommending a two-step increase in Indiana rates with a $28 million annual increase effective upon an IURC order and the remaining $34 million annual increase effective in January 2025 subject to I&M's level of electric plant in service as of December 31, 2024 in comparison to I&M's 2024 forecasted test year. The recommended revenue increase includes: (a) a 9.85% ROE, (b) a two-step update of I&M's Indiana capital structure with a capital structure of 50% for both debt and common equity effective upon an IURC order and a January 2025 update based on I&M's actual capital structure as of December 31, 2024 with common equity not to exceed 51.2%, (c) a $25 million increase related to depreciation expense and (d) an $11 million increase related to storm expenses. In addition, I&M also agreed to withdraw its proposal to defer CAMT and Cook Plant PTCs and to instead include the Indiana jurisdictional impact of Cook Plant PTCs in I&M's Indiana earnings test evaluations. See "Indiana Earnings Test" below for additional information.

In May 2024, the IURC issued an order approving the settlement agreement with minor modifications. In January 2025, in accordance with the IURC's order on I&M's 2023 Indiana base case filing, I&M submitted a filing with the IURC reflecting December 31, 2024 balances of electric plant in service in comparison to I&M's 2024 forecasted test year, resulting in a $15 million annual increase in I&M Indiana base rates effective January 2025.

2023 Michigan Base Rate Case

In September 2023, I&M filed a request with the MPSC for a $34 million annual increase in Michigan base rates based upon a 2024 forecasted test year, a proposed 10.5% ROE and a capital structure of 49.4% debt and 50.6% common equity. The proposed annual increase includes an $11 million annual increase in depreciation expense driven by increased capital investment. I&M's Michigan base case filing requests recovery of certain historical period regulatory asset balances and proposes deferral accounting for certain future investments and tax-related issues, including CAMT expense and PTCs related to the Cook Plant.

In July 2024, the MPSC issued a final order approving an annual base rate increase of $17 million based on a 9.86% ROE and a capital structure of 52% debt and 48% common equity. The MPSC also ordered that Michigan jurisdictional Cook Plant PTCs will be reflected as a deferral in I&M's PSCR reconciliation and rejected I&M's request to defer Michigan jurisdictional CAMT.

Indiana Earnings Test

I&M is required by Indiana law to submit an earnings test evaluation for the most recent one-year and five-year periods as part of I&M's semi-annual Indiana FAC filings. These earnings test evaluations require I&M to include a credit in the FAC factor computation for periods in which I&M earned above its authorized return for both the one-year and five-year periods. The credit is determined as 50% of the lower of the one-year or five-year earnings above the authorized level. Management believes its financial statements adequately address the impact of Indiana earnings test requirements. If future IURC orders require that I&M provide credits in the FAC factor computation, it could reduce future net income and cash flows and impact financial condition.

In July 2024, I&M submitted its FAC filing and earnings test evaluation for the period ended May 2024. In September 2024, an intervenor submitted testimony suggesting that I&M failed to prorate calculations of I&M's authorized net operating income used to establish the earnings test ceiling to reflect the last two Indiana base rate cases. In November 2024, the IURC issued an order on I&M's July 2024 FAC filing concluding that I&M should have prorated the authorized net operating income for the May 2024 earnings test purposes. A resulting over-earnings credit to customers for the earnings test period ending May 2024 of $18 million was included in I&M's updated FAC rates that became effective in December 2024.

In January 2025, I&M submitted its FAC filing and earnings test evaluation for the period ended November 2024. I&M proposed an over-earnings credit to customers for the earnings test period ending November 2024 of $21 million. I&M also proposed to the IURC that intervenor testimony be due in March 2025.

Request to Update AEGCo Depreciation Rates

In October 2022, AEP, on behalf of AEGCo, submitted proposed revisions to AEGCo's depreciation rates for its 50% ownership interest in Rockport Plant, Unit 1 and Unit 2, reflected in the UPA between AEGCo and I&M. The proposed depreciation rates for these assets reflect an estimated 2028 retirement date for the Rockport Plant. AEGCo's previous FERC-approved depreciation rates for Rockport Plant, Unit 1 were based upon a December 31, 2028 estimated retirement date while AEGCo's previous FERC-approved depreciation rates for Rockport Plant, Unit 2 leasehold improvements were based upon a December 31, 2022 estimated retirement date in conjunction with the termination of the Rockport Plant, Unit 2 lease.

In December 2022, the FERC issued an order approving the proposed AEGCo Rockport depreciation rates effective January 1, 2023, subject to further review and a potential refund. In August 2023, AEGCo reached a settlement agreement with the FERC trial staff that resolved all issues set for hearing. In September 2023, the settlement agreement was certified to the FERC as uncontested. In March 2024, the FERC issued an order approving the uncontested settlement agreement. The results of the order did not have a material impact on financial condition, results of operations or cash flows.

FERC 2021 PJM Transmission Formula Rate Challenge

I&M and other AEP subsidiaries transitioned to stand-alone treatment of NOLCs in its PJM and SPP transmission formula rates beginning with the 2022 projected transmission revenue requirements and 2021 true-up to actual transmission revenue requirements, and provided notice of this change in informational filings made with the FERC. Stand-alone treatment of the NOLCs for transmission formula rates increased the annual revenue requirements for years 2024, 2023, 2022 and 2021 by $52 million, $61 million, $69 million and $78 million, respectively.

In January 2024, the FERC issued two orders granting formal challenges by certain unaffiliated customers related to stand-alone treatment of NOLCs in the 2021 Transmission Formula Rates of the AEP transmission owning subsidiaries within PJM and SPP. The FERC directed the AEP transmission owning subsidiaries within PJM and SPP to provide refunds with interest on all amounts collected for the 2021 rate year, and for such refunds to be reflected in the annual update for the next rate year. Accordingly, in the third quarter of 2024, the AEP transmission owning subsidiaries within SPP provided a portion of the 2021 rate year refunds, with the remainder of the refunds expected to be provided in 2025. The AEP transmission owning subsidiaries within PJM are expected to provide their respective refunds for the 2021 rate year in 2025. In February 2024, AEPSC on behalf of the AEP transmission owning subsidiaries within PJM and SPP filed requests for rehearing. In March 2024, the FERC denied AEPSC's requests for rehearing of the January 2024 orders by operation of law and stated it may address the requests for rehearing in future orders. In March 2024, AEPSC submitted refund compliance reports to the FERC, which preserve the non-finality of the FERC's January 2024 orders pending further proceedings on rehearing and appeal. In April 2024, AEPSC made filings with the FERC which request that the FERC: (a) reopen the record so that the FERC may take the IRS PLRs received in April 2024 regarding the treatment of stand-alone NOLCs in ratemaking into evidence and consider them in substantive orders on rehearing and (b) stay its January 2024 orders and related compliance filings and refunds to provide time for consideration of the April 2024 IRS PLRs. In May 2024, AEPSC filed a petition for review with the United States Court of Appeals for the District of Columbia Circuit seeking review of the FERC's January 2024 and March 2024 decisions. In July 2024, the FERC issued orders approving AEPSC's request to reopen the record for the limited purpose of accepting into the record the IRS PLRs and establish additional briefing procedures. In August 2024, AEPSC filed briefs with the FERC requesting the commission modify or overturn their initial orders.

As a result of the January 2024 FERC orders, I&M's balance sheets reflect a liability for the probable refund of all NOLC revenues included in transmission formula rates for years 2024, 2023, 2022 and 2021, with interest. I&M has not yet been directed to make cash refunds related to the 2024, 2023 or 2022 rate years. The probable refunds to affiliated and nonaffiliated customers are reflected as Accumulated Provision for Rate Refunds on the balance sheets, with the exception of amounts expected to be refunded within one year which are reflected in Miscellaneous Current and Accrued Liabilities. Refunds probable to be received by affiliated companies, resulting in a reduction to affiliated transmission expense, were deferred as an increase to Other Regulatory Liabilities or a reduction to Other Regulatory Assets on the balance sheets where management expects that refunds would be returned to retail customers through authorized retail jurisdiction rider mechanisms.

5. EFFECTS OF REGULATION

Regulatory Assets:	December 31, 2024	December 31, 2023	Remaining Recovery Period
	(in millions)		
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Other Regulatory Assets Pending Final Regulatory Approval	$ 6.4	$ 0.2	
Total Regulatory Assets Currently Earning a Return	6.4	0.2	
Regulatory Assets Currently Not Earning a Return			
Income Tax Assets	107.7	103.0	
Plant Retirement Costs - Asset Retirement Obligation Costs (a)	74.0	—	
NOLC Costs - Indiana (b)	26.7	—	
Storm-Related Costs - Indiana	6.3	29.7	
Other Regulatory Assets Pending Final Regulatory Approval	1.6	3.3	
Total Regulatory Assets Currently Not Earning a Return	216.3	136.0	
Total Regulatory Assets Pending Final Regulatory Approval	222.7	136.2	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Cook Plant Uprate Project	20.5	22.9	9 years
Rockport Plant Dry Sorbent Injection System and Selective Catalytic Reduction	16.6	21.1	4 years
Under-recovered Fuel Costs - Michigan	10.6	14.8	1 year
Deferred Cook Plant Life Cycle Management Project Costs - Michigan, FERC	10.1	11.1	10 years
Cook Plant Turbine - Indiana	7.8	8.4	14 years
Other Regulatory Assets Approved for Recovery	21.1	17.5	various
Total Regulatory Assets Currently Earning a Return	86.7	95.8	
Regulatory Assets Currently Not Earning a Return			
Income Tax Assets	299.8	300.7	(c)
Cook Plant Nuclear Refueling Outage Levelization	43.0	55.7	3 years
Storm-Related Costs - Indiana	20.3	—	
Pension and OPEB Funded Status	14.6	25.4	12 years
Excess SO_2 Allowance Inventory - Indiana	11.9	14.8	4 years
Postemployment Benefits	7.3	7.0	3 years
Environmental Cost Rider - Indiana	1.4	8.1	2 years
Other Regulatory Assets Approved for Recovery	20.2	21.0	various
Total Regulatory Assets Currently Not Earning a Return	418.5	432.7	
Total Regulatory Assets Approved for Recovery	505.2	528.5	
Total FERC Account 182.3 Regulatory Assets	$ 727.9	$ 664.7	

(a) See "Federal EPA's Revised CCR Rule" section of Note 6 for additional information.
(b) In the second quarter of 2024, a request seeking to establish a recovery mechanism for these regulatory assets were filed in Indiana. Certain intervenors have challenged the recovery, or have proposed ratemaking treatment that would offset the recovery, of the regulatory assets. In the fourth quarter of 2024, a hearing on the merits was held in Indiana.
(c) Recovered over the period for which the related deferred income tax reverse, which is generally based on the expected life of the underlying assets. Excess ADIT Associated with Certain Depreciable Property is refunded over the remaining depreciable life of the underlying assets. Excess ADIT that is Not Subject to Rate Normalization Requirements was $12 million for the year ended December 31, 2024, and is to be refunded over 4 years.

Regulatory Liabilities:	December 31, 2024	December 31, 2023	Remaining Refund Period
	(in millions)		
Regulatory Liabilities pending final regulatory approval:			
Regulatory Liabilities Currently Not Paying a Return			
FERC 2021 Transmission Formula Rate Challenge Refunds	$ 28.9	$ 22.8	2 years
Cook Plant PTC Deferral - Michigan	14.5	—	
Total Regulatory Liabilities Currently Not Paying a Return	43.4	22.8	
Total Regulatory Liabilities Pending Final Regulatory Approval	43.4	22.8	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Paying a Return			
Income Tax Liabilities (a)	298.7	417.6	(b)
Renewable Energy Surcharge - Michigan	24.3	26.6	2 years
Total Regulatory Liabilities Currently Paying a Return	323.0	444.2	
Regulatory Liabilities Currently Not Paying a Return			
Excess Nuclear Decommissioning Funding	2,137.3	1,721.9	(c)
Spent Nuclear Fuel	50.4	47.6	(c)
Demand Side Management - Indiana	33.0	16.7	2 years
Over-recovered Fuel Costs - Indiana	10.3	23.2	1 year
PJM Costs and Off-system Sales Margin Sharing - Indiana	2.0	14.1	1 year
Other Regulatory Liabilities Approved for Payment	2.2	4.9	various
Total Regulatory Liabilities Currently Not Paying a Return	2,235.2	1,828.4	
Total Regulatory Liabilities Approved for Payment	2,558.2	2,272.6	
Total FERC 254 Account Regulatory Liabilities	$ 2,601.6	$ 2,295.4	

(a) Predominately pays a return due to the inclusion of Excess ADIT in rate base.
(b) Refunded over the period for which the related deferred income tax reverse, which is generally based on the expected life for the underlying assets. Excess ADIT Associated with Certain Depreciable Property is refunded over the remaining depreciable life of the underlying assets. Excess ADIT that is Not Subject to Rate Normalization Requirements was $25 million for the year ended December 31, 2023.
(c) Relieved when plant is decommissioned.

6. COMMITMENTS, GUARANTEES AND CONTINGENCIES

I&M is subject to certain claims and legal actions arising in the ordinary course of business. In addition, I&M's business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation cannot be predicted. Management accrues contingent liabilities only when management concludes that it is both probable that a liability has been incurred at the date of the financial statements and the amount of loss can be reasonably estimated. When management determines that it is not probable, but rather reasonably possible that a liability has been incurred at the date of the financial statements, management discloses such contingencies and the possible loss or range of loss if such estimate can be made. Any estimated range is based on currently available information and involves elements of judgment and significant uncertainties. Any estimated range of possible loss may not represent the maximum possible loss exposure. Circumstances change over time and actual results may vary significantly from estimates.

For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on the financial statements.

COMMITMENTS

I&M has substantial commitments for fuel, energy and capacity contracts as part of the normal course of business. Certain contracts contain penalty provisions for early termination.

In accordance with the accounting guidance for "Commitments", the following table summarizes I&M's actual contractual commitments as of December 31, 2024:

Contractual Commitments	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 151.5	$ 346.6	$ 220.7	$ 263.9	$ 982.7
Energy and Capacity Purchase Contracts	119.9	236.2	231.7	321.5	909.3
Total	$ 271.4	$ 582.8	$ 452.4	$ 585.4	$ 1,892.0

(a) Represents contractual commitments to purchase coal, natural gas, uranium and other consumables as fuel for electric generation along with related transportation of the fuel.

GUARANTEES

Liabilities for guarantees are recorded in accordance with the accounting guidance for "Guarantees." There is no collateral held in relation to any guarantees. In the event any guarantee is drawn, there is no recourse to third-parties unless specified below.

Indemnifications and Other Guarantees

I&M enters into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. As of December 31, 2024, there were no material liabilities recorded for any indemnifications.

AEPSC conducts power purchase-and-sale activity on behalf of I&M who are jointly and severally liable for activity conducted on their behalf.

Lease Obligations

I&M leases equipment under master lease agreements. See "Master Lease Agreements" section of Note 12 for additional information.

ENVIRONMENTAL CONTINGENCIES

Federal EPA's Revised CCR Rule

In April 2024, the Federal EPA finalized revisions to the CCR Rule to expand the scope of the rule to include inactive impoundments at inactive facilities ("legacy CCR surface impoundments") as well as to establish requirements for currently exempt solid waste management units that involve the direct placement of CCR on the land ("CCR management units"). The Federal EPA is requiring that owners and operators of legacy surface impoundments comply with all of the existing CCR Rule requirements applicable to inactive CCR surface impoundments at active facilities, except for the location restrictions and liner design criteria. The rule establishes compliance deadlines for legacy surface impoundments to meet regulatory requirements, including a requirement to initiate closure within five years after the effective date of the final rule. The rule requires evaluations to be completed at both active facilities and inactive facilities with one or more legacy surface impoundments. Closure may be accomplished by applying an impermeable cover system over the CCR material ("closure in place") or the CCR material may be excavated and placed in a compliant landfill ("closure by removal"). Groundwater monitoring and other analysis over the next three years will provide additional information on the planned closure method. AEP evaluated the applicability of the rule to current and former plant sites and recorded incremental ARO in the second quarter of 2024, as shown in the table below, based on initial cost estimates primarily reflecting compliance with the rule through closure in place and future groundwater monitoring requirements pursuant to the revised CCR Rule.

Increase in ARO	Increase in Other Regulatory Assets (a)	Charged to Operating Expenses (b)
	(in millions)	
$ 85.7	$ 72.3	$ 13.4

(a) ARO is related to a legacy CCR surface impoundment or CCR management unit at a retired generation facility and recognition of a regulatory asset in accordance with the accounting guidance for "Regulated Operations" is supported.

(b) ARO is related to a legacy CCR surface impoundment or CCR management unit and recognition of a regulatory asset in accordance with the accounting guidance for "Regulated Operations" is not yet supported.

As further groundwater monitoring and other analysis is performed, management expects to refine the assumptions and underlying cost estimates used in recording the ARO. These refinements may include, but are not limited to, changes in the expected method of closure, changes in estimated quantities of CCR at each site, the identification of new CCR management units, among other items. These future changes could have a material impact on the ARO and materially reduce future net income and cash flows and further impact financial condition.

AEP will seek cost recovery through regulated rates, including proposal of new regulatory mechanisms for cost recovery where existing mechanisms are not applicable. The rule could have an additional, material adverse impact on net income, cash flows and financial condition if AEP cannot ultimately recover these additional costs of compliance. Several parties, including AEP and one of its trade associations, have filed petitions for review of the rule with the U.S. Court of Appeals for the D.C. Circuit. One of the parties also filed a motion to stay the rule pending the outcome of the litigation. In November 2024, the court denied the stay motion. Management cannot predict the outcome of the litigation.

The Comprehensive Environmental Response Compensation and Liability Act (Superfund) and State Remediation

By-products from the generation of electricity include materials such as ash, slag, sludge, low-level radioactive waste and SNF. Coal combustion by-products, which constitute the overwhelming percentage of these materials, are typically treated and deposited in captive disposal facilities or are beneficially utilized. In addition, the generation plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls and other hazardous and non-hazardous materials. I&M currently incurs costs to dispose of these substances safely.

Superfund addresses clean-up of hazardous substances that are released to the environment. The Federal EPA administers the clean-up programs. Several states enacted similar laws. As of December 31, 2024, I&M received information requests for three sites that could lead to a Potentially Responsible Party (PRP) designation. In those instances where a PRP or defendant has been named, disposal or recycling activities were in accordance with the then-applicable laws and regulations. Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories. Liability has been resolved for a number of sites with no significant effect on net income.

Management evaluates the potential liability for each Superfund site separately, but several general statements can be made about potential future liability. Allegations that materials were disposed at a particular site are often unsubstantiated and the quantity of materials deposited at a site can be small and often non-hazardous. Although Superfund liability has been interpreted by the courts as joint and several, typically many parties are named as PRPs for each site and several of the parties are financially sound enterprises. As of December 31, 2024, management's estimates do not anticipate material clean-up costs for identified Superfund sites.

NUCLEAR CONTINGENCIES

I&M owns and operates the two-unit 2,296 MW Cook Plant under licenses granted by the NRC. I&M has a significant future financial commitment to dispose of SNF and to safely decommission and decontaminate the plant. The licenses to operate the two nuclear units at the Cook Plant expire in 2034 and 2037. Management has started the application process for license extensions for both units that would extend Unit 1 and Unit 2 to 2054 and 2057, respectively. The operation of a nuclear facility also involves special risks, potential liabilities and specific regulatory and safety requirements. By agreement, I&M is partially liable, together with all other electric utility companies that own nuclear generation units, for a nuclear power plant incident at any nuclear plant in the U.S. Should a nuclear incident occur at any nuclear power plant in the U.S., the resultant liability could be substantial.

Decommissioning and Low-Level Waste Accumulation Disposal

The costs to decommission a nuclear plant are affected by NRC regulations and the SNF disposal program. Decommissioning costs are accrued over the service life of Cook Plant. The most recent decommissioning cost study was performed in 2024. According to that study, stated in 2024 undiscounted dollars, the estimated cost of decommissioning and disposal of low-level radioactive waste was $2.4 billion, with additional ongoing costs of $7 million per year for post decommissioning storage of SNF and an eventual cost of $45 million for the subsequent decommissioning of the SNF storage facility. I&M recovers estimated decommissioning costs for the Cook Plant in its rates. The amounts recovered in rates were $1 million and $2 million for the years ended December 31, 2024 and 2023, respectively. Decommissioning costs recovered from customers are deposited in external trusts.

As of December 31, 2024 and 2023, the total decommissioning trust fund balances were $4 billion and $3.5 billion, respectively. The increase in the trust fund balance was driven by favorable investment performance in 2024. Trust fund earnings increase the fund assets and may decrease the amount remaining to be recovered from customers. Trust fund losses decrease the fund assets and may increase the amount remaining to be recovered from customers. The decommissioning costs (including unrealized gains and losses, interest and trust funds expenses) increase or decrease the recorded liability.

I&M continues to work with regulators and customers to establish rates designed to collect the estimated costs of decommissioning the Cook Plant. However, future net income and cash flows would be reduced and financial condition could be impacted if the cost of SNF disposal and decommissioning increases and cannot be recovered.

Spent Nuclear Fuel Disposal

The federal government is responsible for permanent SNF disposal and assesses fees to nuclear plant owners for SNF disposal. A fee of one-mill per KWh for fuel consumed after April 6, 1983 at the Cook Plant was collected from customers and remitted to the DOE through May 14, 2014. In May 2014, pursuant to court order from the U.S Court of Appeals for the District of Columbia Circuit, the DOE adjusted the fee to $0. As of December 31, 2024 and 2023, fees and related interest of $316 million and $300 million, respectively, for fuel consumed prior to April 7, 1983 were recorded as Long-term Debt and funds collected from customers along with related earnings totaling $367 million and $348 million, respectively, to pay the fee, were recorded as part of Other Special Funds on the balance sheets. I&M has not paid the government the pre-April 1983 fees due to continued delays and uncertainties related to the federal disposal program.

In 2011, I&M signed a settlement agreement with the federal government which permits I&M to make annual filings to recover certain SNF storage costs incurred as a result of the government's delay in accepting SNF for permanent storage. Under the settlement agreement, I&M received $12 million and $21 million in 2024 and 2023, respectively, to recover costs and will be eligible to receive additional payment of annual claims for allowed costs that are incurred through December 31, 2024. The proceeds reduced costs for dry cask storage. As of December 31, 2024 and 2023, I&M deferred $11 million and $12 million, respectively, in Miscellaneous Current and Accrued Assets and $15 million and $9 million, respectively, in Miscellaneous Deferred Debits on the balance sheets for dry cask storage and related operation and maintenance costs for recovery under this agreement. See "Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal" section of Note 10 for additional information.

Nuclear Insurance

I&M carries nuclear property insurance of $2.7 billion to cover a nuclear incident at Cook Plant including coverage for decontamination and stabilization, as well as premature decommissioning caused by a nuclear incident. Insurance coverage for a nonnuclear property incident at Cook Plant is $750 million. Additional insurance provides coverage for a weekly indemnity payment resulting from an insured accidental outage. I&M utilizes industry mutual insurers for the placement of this insurance coverage. Coverage from these industry mutual insurance programs require a contingent financial obligation of up to $47 million for I&M, which is assessable if the insurer's financial resources would be inadequate to pay for industry losses.

The Price-Anderson Act, extended through December 31, 2025, establishes insurance protection for public nuclear liability arising from a nuclear incident of $16.3 billion and applies to any incident at a licensed reactor in the U.S. Commercially available insurance, which must be carried for each licensed reactor, provides $500 million of primary coverage. In the event of a nuclear incident at any nuclear plant in the U.S., the remainder of the liability would be provided by a deferred premium assessment of $332 million per nuclear incident on Cook Plant's reactors payable in annual installments of $49 million. The number of incidents for which payments could be required is not limited.

In the event of an incident of a catastrophic nature, I&M is covered for public nuclear liability for the first $500 million through commercially available insurance. The next level of liability coverage of up to $15.8 billion would be covered by claim premium assessments made under the Price-Anderson Act. In the event nuclear losses or liabilities are underinsured or exceed accumulated funds, I&M would seek recovery of those amounts from customers through a rate increase. If recovery from customers is not possible, it could reduce future net income and cash flows and impact financial condition.

OPERATIONAL CONTINGENCIES

Insurance and Potential Losses

I&M maintains insurance coverage normal and customary for electric utilities, subject to various deductibles. I&M also maintains property and casualty insurance that may cover certain physical damage or third-party injuries caused by cybersecurity incidents. Insurance coverage includes all risks of physical loss or damage to nonnuclear assets, subject to insurance policy conditions and exclusions. Covered property generally includes power plants, substations, facilities and inventories. Excluded property generally includes transmission and distribution lines, poles and towers. The insurance programs also generally provide coverage against loss arising from certain claims made by third-parties and are in excess of retentions absorbed by I&M. Coverage is generally provided by a combination of the protected cell of EIS and/or various industry mutual and/or commercial insurance carriers. See "Nuclear Contingencies" section above for additional information.

In July 2024, I&M renewed insurance programs including coverage for wildfire liability. Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including, but not limited to, liabilities relating to a cybersecurity incident, extreme weather or wildfire related liabilities or damage to the Cook Plant and costs of replacement power in the event of an incident at the Cook Plant. Future losses or liabilities, if they occur, which are not completely insured, unless recovered through the rate-making process, could reduce future net income and cash flows and impact financial condition.

7. BENEFIT PLANS

For a discussion of investment strategy, investment limitations, target asset allocations and the classification of investments within the fair value hierarchy, see "Fair Value Measurements of Assets and Liabilities" and "Investments Held in Trust for Future Liabilities" sections of Note 1.

I&M participates in an AEPSC sponsored qualified pension plan and two unfunded non-qualified pension plans. Substantially all employees are covered by the qualified plan or both the qualified and a non-qualified pension plan. I&M also participates in OPEB plans sponsored by AEPSC to provide health and life insurance benefits for retired employees.

I&M recognizes the funded status associated with defined benefit pension and OPEB plans on the balance sheets. Disclosures about the plans are required by the "Compensation – Retirement Benefits" accounting guidance. I&M recognizes an asset for a plan's overfunded status or a liability for a plan's underfunded status, and recognize, as a component of other comprehensive income, the changes in the funded status of the plan that arise during the year that are not recognized as a component of net periodic benefit cost. I&M records a regulatory asset instead of other comprehensive income for qualifying benefit costs of regulated operations that for rate-making purposes are deferred for future recovery. The cumulative funded status adjustment is equal to the remaining unrecognized deferrals for unamortized actuarial losses or gains, prior service costs and transition obligations, such that remaining deferred costs result in an AOCI equity reduction or regulatory asset and deferred gains result in an AOCI equity addition or regulatory liability.

Actuarial Assumptions for Benefit Obligations

The weighted-average assumptions used in the measurement of I&M's benefit obligations are shown in the following table:

	Pension Plans		OPEB	
	December 31,			
Assumption	2024	2023	2024	2023
Discount Rate	5.65%	5.15%	5.60%	5.15%
Interest Crediting Rate	4.55%	4.00%	NA	NA
Rate of Compensation Increase	5.50% (a)	5.05% (a)	NA	NA

(a) Rates are for base pay only. In addition, an amount is added to reflect target incentive compensation for exempt employees and overtime and incentive pay for nonexempt employees.
NA Not applicable.

A duration-based method is used to determine the discount rate for the plans. A hypothetical portfolio of high quality corporate bonds is constructed with cash flows matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan.

For 2024, the rate of compensation increase assumed varies with the age of the employee, ranging from 3% per year to 11.5% per year, with the average increase shown in the table above.

Actuarial Assumptions for Net Periodic Benefit Costs

The weighted-average assumptions used in the measurement of I&M's benefit costs are shown in the following table:

	Pension Plans		OPEB	
	Year Ended December 31,			
Assumption	2024	2023	2024	2023
Discount Rate	5.20 %	5.50 %	5.15 %	5.50 %
Interest Crediting Rate	4.05 %	4.25 %	NA	NA
Expected Return on Plan Assets	7.30 %	7.50 %	6.75 %	7.25 %
Rate of Compensation Increase	5.10 % (a)	5.05 % (a)	NA	NA

(a) Rates are for base pay only. In addition, an amount is added to reflect target incentive compensation for exempt employees and overtime and incentive pay for nonexempt employees.
NA Not applicable.

The expected return on plan assets was determined by evaluating historical returns, the current investment climate (yield on fixed income securities and other recent investment market indicators), rate of inflation, third-party forecasts and current prospects for economic growth.

The health care trend rate assumptions used for OPEB plans measurement purposes are shown below:

	December 31,	
Health Care Trend Rates	2024	2023
Initial	6.50 %	7.00 %
Ultimate	4.50 %	4.50 %
Year Ultimate Reached	2029	2030

Significant Concentrations of Risk within Plan Assets

In addition to establishing the target asset allocation of plan assets, the investment policy also places restrictions on securities to limit significant concentrations within plan assets. The investment policy establishes guidelines that govern maximum market exposure, security restrictions, prohibited asset classes, prohibited types of transactions, minimum credit quality, average portfolio credit quality, portfolio duration and concentration limits. The guidelines were established to mitigate the risk of loss due to significant concentrations in any investment. Management monitors the plans to control security diversification and ensure compliance with the investment policy. As of December 31, 2024, the assets were invested in compliance with all investment limits. See "Investments Held in Trust for Future Liabilities" section of Note 1 for limit details.

Benefit Plan Obligations, Plan Assets, Funded Status and Amounts Recognized on the Balance Sheets

For the year ended December 31, 2024, the pension plans had an actuarial gain primarily due to an increase in discount rates, and to a lesser extent the effect of demographic experience (updated census data on January 1, 2024). These gains were partially offset by increasing the cash balance account interest crediting rate, increasing the rate used to convert lump sums to annuities and updating the compensation increase rate to reflect the results of an experience study conducted in 2024. For the year ended December 31, 2024, the OPEB plans had an actuarial gain primarily due to updated per capita cost assumptions and updated discount rates. These gains were partially offset by the addition of a life insurance administrative load of 5%, the effect of special termination benefits and earlier retirements due to the voluntary severance program that occurred in the second quarter of 2024 and assumption changes as a result of an experience study conducted in 2024. For the year ended December 31, 2023, the pension plans had an actuarial loss primarily due to a decrease in the discount rate, and to a lesser extent the effect of demographic experience (updated census data on January 1, 2023). These losses were partially offset by decreasing the cash balance account interest crediting rate. For the year ended December 31, 2023, the OPEB plans had an actuarial loss primarily due to discount rates, as well as actual benefit payments above expected. These losses were partially offset by updated per capita cost assumptions. The following tables provide a reconciliation of the changes in the plans' benefit obligations, fair value of plan assets, funded status and the presentation on the balance sheets. The benefit obligation for the defined benefit pension and OPEB plans are the projected benefit obligation and the accumulated benefit obligation, respectively.

	Pension Plans		OPEB	
	2024	2023	2024	2023
Change in Benefit Obligation	(in millions)			
Benefit Obligation as of January 1,	$ 477.0	$ 466.8	$ 98.8	$ 101.9
Service Cost	13.0	11.9	0.6	0.6
Interest Cost	23.9	24.9	4.8	5.4
Actuarial (Gain) Loss	(8.4)	8.5	(24.7)	3.2
Settlements	(33.1)	—	—	—
Special/Contractual Termination Benefits	—	—	0.4	—
Benefit Payments	(22.6)	(35.1)	(13.4)	(18.3)
Participant Contributions	—	—	6.0	6.0
Benefit Obligation as of December 31,	$ 449.8	$ 477.0	$ 72.5	$ 98.8
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 550.6	$ 533.7	$ 204.6	$ 190.5
Actual Gain (Loss) on Plan Assets	11.6	51.5	14.7	26.4
Company Contributions	—	0.5	—	—
Participant Contributions	—	—	6.0	6.0
Settlements	(33.1)	—	—	—
Benefit Payments	(22.6)	(35.1)	(13.4)	(18.3)
Fair Value of Plan Assets as of December 31,	$ 506.5	$ 550.6	$ 211.9	$ 204.6
Funded Status as of December 31,	$ 56.7	$ 73.6	$ 139.4	$ 105.8

	Pension Plans		OPEB	
	December 31,			
	2024	2023	2024	2023
	(in millions)			
Special Funds – Prepaid Benefit Costs	$ 58.2	$ 74.8	$ 139.4	$ 105.8
Accumulated Provision for Pensions and Benefits – Long-term Benefit Liability	(1.5)	(1.2)	—	—
Funded Status	$ 56.7	$ 73.6	$ 139.4	$ 105.8

Amounts Included in Regulatory Assets, Deferred Income Taxes and AOCI

The following tables show the components of the plans included in Regulatory Assets, Deferred Income Taxes and AOCI and the items attributable to the change in these components:

	Pension Plans		OPEB	
	December 31,			
	2024	2023	2024	2023
Components	(in millions)			
Net Actuarial (Gain) Loss	$ 7.5	$ (5.8)	$ 2.3	$ 28.7
Prior Service Credit	—	—	(2.0)	(3.7)
Recorded as				
Regulatory Assets	$ 17.5	$ 6.4	$ (2.9)	$ 19.0
Deferred Income Taxes	(2.2)	(2.6)	0.7	1.3
Net of Tax AOCI	(7.8)	(9.6)	2.5	4.7

	Pension Plans		OPEB	
	2024	2023	2024	2023
Components	(in millions)			
Actuarial (Gain) Loss During the Year	$ 23.0	$ 1.2	$ (25.9)	$ (9.6)
Amortization of Actuarial Loss	(0.4)	(0.1)	(0.5)	(1.9)
Amounts Recognized Due to Settlement	(9.3)	—	—	—
Amortization of Prior Service Credit	—	—	1.7	8.7
Change for the Year Ended December 31,	$ 13.3	$ 1.1	$ (24.7)	$ (2.8)

Determination of Pension Expense

The determination of pension expense or income is based on a market-related valuation of assets which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return.

Pension and OPEB Assets

The fair value tables within Pension and OPEB Assets present the classification of assets for AEP within the fair value hierarchy. All Level 1, 2, 3 and Other amounts can be allocated to I&M using the percentages in the table below:

Pension Plan		OPEB	
December 31,			
2024	2023	2024	2023
13.8 %	13.4 %	11.9 %	12.2 %

The following table presents the classification of pension plan assets for AEP within the fair value hierarchy as of December 31, 2024:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
	(in millions)					
Equities (a):						
Domestic	$ 327.0	$ —	$ —	$ —	$ 327.0	8.9 %
International	290.2	—	—	—	290.2	7.9 %
Common Collective Trusts (b)	176.1	—	—	472.6	648.7	17.7 %
Subtotal – Equities	793.3	—	—	472.6	1,265.9	34.5 %
Fixed Income (a):						
United States Government and Agency Securities	(2.3)	865.6	—	—	863.3	23.6 %
Corporate Debt	—	719.2	—	—	719.2	19.6 %
Foreign Debt	—	136.1	—	—	136.1	3.7 %
State and Local Government	—	25.8	—	—	25.8	0.7 %
Other – Asset Backed	—	0.9	—	—	0.9	— %
Subtotal – Fixed Income	(2.3)	1,747.6	—	—	1,745.3	47.6 %
Infrastructure (b)	—	—	—	112.9	112.9	3.1 %
Real Estate (b)	—	—	—	227.9	227.9	6.2 %
Alternative Investments (b)	—	—	—	223.8	223.8	6.1 %
Cash and Cash Equivalents (b)	—	41.3	—	27.2	68.5	1.9 %
Other – Pending Transactions and Accrued Income (c)	—	—	—	21.9	21.9	0.6 %
Total	$ 791.0	$ 1,788.9	$ —	$ 1,086.3	$ 3,666.2	100.0 %

(a) Includes investment securities loaned to borrowers under the securities lending program. See the "Investments Held in Trust for Future Liabilities" section of Note 1 for additional information.
(b) Amounts in "Other" column represent investments for which fair value is measured using net asset value per-share.
(c) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following table presents the classification of OPEB plan assets for AEP within the fair value hierarchy as of December 31, 2024:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 616.8	$ —	$ —	$ —	$ 616.8	34.7 %
International	267.2	—	—	—	267.2	15.0 %
Common Collective Trusts (a)	64.2	—	—	129.4	193.6	10.9 %
Subtotal – Equities	948.2	—	—	129.4	1,077.6	60.6 %
Fixed Income:						
Common Collective Trust – Debt (a)	—	—	—	132.9	132.9	7.5 %
United States Government and Agency Securities	(0.5)	157.6	—	—	157.1	8.9 %
Corporate Debt	—	132.3	—	—	132.3	7.5 %
Foreign Debt	—	27.1	—	—	27.1	1.5 %
State and Local Government	57.8	5.0	—	—	62.8	3.5 %
	—	0.2	—	—	0.2	— %
Subtotal – Fixed Income	57.3	322.2	—	132.9	512.4	28.9 %
Trust Owned Life Insurance:						
International Equities	—	23.1	—	—	23.1	1.3 %
United States Bonds	—	118.2	—	—	118.2	6.7 %
Subtotal – Trust Owned Life Insurance	—	141.3	—	—	141.3	8.0 %
Cash and Cash Equivalents (a)	27.6	—	—	3.1	30.7	1.7 %
Other – Pending Transactions and Accrued Income (b)	—	—	—	13.9	13.9	0.8 %
Total	$ 1,033.1	$ 463.5	$ —	$ 279.3	$ 1,775.9	100.0 %

(a) Amounts in "Other" column represent investments for which fair value is measured using net asset value per-share.
(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following table presents the classification of pension plan assets for AEP within the fair value hierarchy as of December 31, 2023:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities (a):						
Domestic	$ 411.3	$ —	$ —	$ —	$ 411.3	10.0 %
International	389.8	—	—	—	389.8	9.5 %
Common Collective Trusts (b)	—	—	—	420.9	420.9	10.2 %
Subtotal – Equities	801.1	—	—	420.9	1,222.0	29.7 %
Fixed Income (a):						
United States Government and Agency Securities	8.3	1,099.2	—	—	1,107.5	26.9 %
Corporate Debt	—	894.8	—	—	894.8	21.7 %
Foreign Debt	—	167.1	—	—	167.1	4.1 %
State and Local Government	—	38.7	—	—	38.7	0.9 %
Other – Asset Backed	—	1.3	—	—	1.3	— %
Subtotal – Fixed Income	8.3	2,201.1	—	—	2,209.4	53.6 %
Infrastructure (b)	—	—	—	101.4	101.4	2.5 %
Real Estate (b)	—	—	—	239.3	239.3	5.8 %
Alternative Investments (b)	—	—	—	241.8	241.8	5.8 %
Cash and Cash Equivalents (b)	—	51.0	—	33.8	84.8	2.1 %
Other – Pending Transactions and Accrued Income (c)	—	—	0.1	19.4	19.5	0.5 %
Total	$ 809.4	$ 2,252.1	$ 0.1	$ 1,056.6	$ 4,118.2	100.0 %

(a) Includes investment securities loaned to borrowers under the securities lending program. See the "Investments Held in Trust for Future Liabilities" section of Note 1 for additional information.
(b) Amounts in "Other" column represent investments for which fair value is measured using net asset value per-share.
(c) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following table presents the classification of OPEB plan assets for AEP within the fair value hierarchy as of December 31, 2023:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 540.6	$ —	$ —	$ —	$ 540.6	32.3 %
International	288.4	—	—	—	288.4	17.2 %
Common Collective Trusts (a)	—	—	—	131.6	131.6	7.9 %
Subtotal – Equities	829.0	—	—	131.6	960.6	57.4 %
Fixed Income:						
Common Collective Trust – Debt (a)	—	—	—	146.7	146.7	8.8 %
United States Government and Agency Securities	1.4	163.3	—	—	164.7	9.8 %
Corporate Debt	—	149.0	—	—	149.0	8.9 %
Foreign Debt	—	28.6	—	—	28.6	1.7 %
State and Local Government	41.5	7.8	—	—	49.3	3.0 %
Other - Asset Backed	—	0.2	—	—	0.2	— %
Subtotal – Fixed Income	42.9	348.9	—	146.7	538.5	32.2 %
Trust Owned Life Insurance:						
International Equities	—	22.3	—	—	22.3	1.3 %
United States Bonds	—	130.0	—	—	130.0	7.8 %
Subtotal – Trust Owned Life Insurance	—	152.3	—	—	152.3	9.1 %
Cash and Cash Equivalents (a)	25.9	—	—	2.9	28.8	1.7 %
Other – Pending Transactions and Accrued Income (b)	—	—	—	(6.9)	(6.9)	(0.4)%
Total	$ 897.8	$ 501.2	$ —	$ 274.3	$ 1,673.3	100.0 %

(a) Amounts in "Other" column represent investments for which fair value is measured using net asset value per-share.
(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

Accumulated Benefit Obligation

The accumulated benefit obligation for the pension plans is as follows:

Accumulated Benefit Obligation	December 31, 2024	2023
	(in millions)	
Qualified Pension Plan	$ 422.3	$ 450.3
Nonqualified Pension Plans	0.9	0.7
Total	$ 423.2	$ 451.0

Obligations in Excess of Fair Values

The tables below show the underfunded pension plans that had obligations in excess of plan assets.

Projected Benefit Obligation

	December 31, 2024	2023
	(in millions)	
Projected Benefit Obligation	$ 1.5	$ 1.2
Fair Value of Plan Assets	—	—
Underfunded Projected Benefit Obligation	$ (1.5)	$ (1.2)

Accumulated Benefit Obligation

	December 31, 2024	2023
	(in millions)	
Accumulated Benefit Obligation	$ 0.9	$ 0.7
Fair Value of Plan Assets	—	—
Underfunded Accumulated Benefit Obligation	$ (0.9)	$ (0.7)

Estimated Future Benefit Payments and Contributions

I&M expects contributions and payments for the pension plans of $3 million during 2024. For the pension plans, this amount includes the payment of unfunded nonqualified benefits plus contributions to the qualified trust fund of at least the minimum amount required by the Employee Retirement Income Security Act. For the qualified pension plan, I&M may also make additional discretionary contributions to maintain the funded status of the plan.

The table below reflects the total benefits expected to be paid from the plan or from I&M's assets. The payments include the participants' contributions to the plan for their share of the cost. Future benefit payments are dependent on the number of employees retiring, whether the retiring employees elect to receive pension benefits as annuities or as lump sum distributions, future integration of the benefit plans with changes to Medicare and other legislation, future levels of interest rates and variances in actuarial results. The estimated payments for the pension benefits and OPEB are as follows:

	Estimated Payments	
	Pension Plans	OPEB
	(in millions)	
2025	$ 40.1	$ 14.5
2026	40.1	14.5
2027	39.0	14.2
2028	38.8	13.9
2029	37.1	13.6
Years 2030 to 2034, in Total	179.0	61.0

Components of Net Periodic Benefit Cost

The following table provides the components of net periodic benefit cost (credit) for the plans:

	Pension Plans		OPEB	
	Years Ended December 31,			
	2024	2023	2024	2023
	(in millions)			
Service Cost	$ 13.0	$ 11.9	$ 0.6	$ 0.6
Interest Cost	23.9	24.9	4.8	5.4
Expected Return on Plan Assets	(42.9)	(44.2)	(13.5)	(13.5)
Amortization of Prior Service Credit	—	—	(1.7)	(8.7)
Amortization of Net Actuarial Loss	0.4	0.1	0.5	1.9
Settlements (a)	9.3	—	—	—
Special/Contractual Termination Benefits	—	—	0.3	—
Net Periodic Benefit Cost (Credit)	3.7	(7.3)	(9.0)	(14.3)
Capitalized Portion	(3.9)	(3.6)	(0.2)	(0.2)
Net Periodic Benefit Credit Recognized in Expense	$ (0.2)	$ (10.9)	$ (9.2)	$ (14.5)

(a) I&M will seek recovery for the portion of pension settlement costs related to regulated operations.

American Electric Power System Retirement Savings Plan

I&M participates in an AEPSC sponsored defined contribution retirement savings plan, the American Electric Power System Retirement Savings Plan, for substantially all employees. This qualified plan offers participants an opportunity to contribute a portion of their pay, includes features under Section 401(k) of the Internal Revenue Code and provides for company matching contributions. The matching contributions to the plan are 100% of the first 1% of eligible employee contributions and 70% of the next 5% of contributions. The cost for matching contributions to the retirement savings plans for the years ended December 31, 2024 and 2023 were $11 million and $11 million, respectively.

8. BUSINESS SEGMENTS

I&M has one reportable segment, an electricity generation, transmission and distribution business. I&M's other activities are insignificant. I&M's operations are managed on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight on the business process, cost structures and operating results. The CODM of I&M is the AEP President and CEO, who makes operating decisions, allocates resources to and assesses performance based on these reportable segments. The CODM uses net income (loss) that is reported on I&M's statements of income as a measure of segment profit or loss in making these decisions. Net income (loss) includes intercompany revenues and expenses that are eliminated on the consolidated financial statements. The expenses disclosed on I&M's statements of income align with the segment-level significant expenses that are regularly provided to the CODM. Total Assets is reported on the consolidated financial statements. Gross Additions to Plants for I&M is represented by the sum of Construction and Acquisition of Plant on the consolidated financial statements. See I&M's statements of income, balance sheets and cash flows for details.

9. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

AEPSC is agent for and transacts on behalf of I&M.

I&M is exposed to certain market risks as major power producer and participant in the electricity, capacity, natural gas, coal and emission allowance markets. These risks include commodity price risks which may be subject to capacity risk, interest rate risk and credit risk. These risks represent the risk of loss that may impact I&M due to changes in the underlying market prices or rates. Management utilizes derivative instruments to manage these risks.

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Risk Management Strategies

The strategy surrounding the use of derivative instruments primarily focuses on managing risk exposures, future cash flows and creating value utilizing both economic and formal hedging strategies. The risk management strategies also include the use of derivative instruments for trading purposes which focus on seizing market opportunities to create value driven by expected changes in the market prices of the commodities. To accomplish these objectives, I&M primarily employs risk management contracts including physical and financial forward purchase-and-sale contracts and, to a lesser extent, OTC swaps and options. Not all risk management contracts meet the definition of a derivative under the accounting guidance for "Derivatives and Hedging." Derivative risk management contracts elected normal under the normal purchases and normal sales scope exception are not subject to the requirements of this accounting guidance.

I&M utilizes power, capacity, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other commodity contracts to manage the risk associated with the energy business. I&M utilizes interest rate derivative contracts in order to manage the interest rate exposure associated with the commodity portfolio. For disclosure purposes, such risks are grouped as "Commodity," as these risks are related to energy risk management activities. I&M also utilizes derivative contracts to manage interest rate risk associated with debt financing. For disclosure purposes, these risks are grouped as "Interest Rate." The amount of risk taken is determined by the Commercial Operations and Finance groups in accordance with established risk management policies as approved by the Finance Committee of the Board of Directors.

The following table represents the gross notional volume of I&M's outstanding derivative contracts:

Notional Volume of Derivative Instruments

Primary Risk Exposure	2024	2023	Unit of Measure
	(in millions)		
Commodity:			
Power	7.7	5.9	MWhs
Heating Oil and Gasoline	2.0	0.6	Gallons

Cash Flow Hedging Strategies

I&M utilizes cash flow hedges on certain derivative transactions for the purchase-and-sale of power ("Commodity") in order to manage the variable price risk related to forecasted purchases and sales. Management monitors the potential impacts of commodity price changes and, where appropriate, enters into derivative transactions to protect profit margins for a portion of future electricity sales and purchases. I&M does not hedge all commodity price risk.

I&M utilizes a variety of interest rate derivative transactions in order to manage interest rate risk exposure. I&M also utilizes interest rate derivative contracts to manage interest rate exposure related to future borrowings of fixed-rate debt. I&M does not hedge all interest rate exposure.

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON THE FINANCIAL STATEMENTS

The accounting guidance for "Derivatives and Hedging" requires recognition of all qualifying derivative instruments as either assets or liabilities on the balance sheets at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes and other assumptions. In order to determine the relevant fair values of the derivative instruments, I&M applies valuation adjustments for discounting, liquidity and credit quality.

Credit risk is the risk that a counterparty will fail to perform on the contract or fail to pay amounts due. Liquidity risk represents the risk that imperfections in the market will cause the price to vary from estimated fair value based upon prevailing market supply and demand conditions. Since energy markets are imperfect and volatile, there are inherent risks related to the underlying assumptions in models used to fair value risk management contracts. Unforeseen events may cause reasonable price curves to differ from actual price curves throughout a contract's term and at the time a contract settles. Consequently, there could be significant adverse or favorable effects on future net income and cash flows if market prices are not consistent with management's estimates of current market consensus for forward prices in the current period. This is particularly true for longer term contracts. Cash flows may vary based on market conditions, margin requirements and the timing of settlement of risk management contracts.

According to the accounting guidance for "Derivatives and Hedging," I&M reflects the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, I&M is required to post or receive cash collateral based on third-party contractual agreements and risk profiles. There was no cash collateral received from third-parties netted against short-term and long-term risk management assets for I&M as of December 31, 2024 and 2023. The amount of cash collateral paid to third-parties netted against short-term and long-term risk management liabilities was not material for I&M as of December 31, 2024 and 2023.

The following tables represent the gross fair value of I&M's derivative activity on the balance sheets.

	December 31, 2024		
Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	(in millions)		
Derivative Instrument Assets	$ 29.7	$ (11.3)	$ 18.4
Long-Term Portion of Derivative Instrument Assets	1.2	(1.2)	—
Derivative Instrument Liabilities	12.6	(11.9)	0.7
Long-Term Portion of Derivative Instrument Liabilities	2.1	(1.7)	0.4

	December 31, 2023		
Balance Sheet Location	Risk Management Contracts - Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	(in millions)		
Derivative Instrument Assets	$ 42.1	$ (2.5)	$ 39.6
Long-Term Portion of Derivative Instrument Assets	12.0	(0.2)	11.8
Derivative Instrument Liabilities	5.6	(3.6)	2.0
Long-Term Portion of Derivative Instrument Liabilities	0.2	(0.2)	—

(a) Derivative instruments within this category are disclosed as gross. These instruments are subject to master netting agreements and are presented on the balance sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."
(b) Amounts include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging."
(c) All derivative contracts subject to a master netting arrangement or similar agreement are offset in the statement of financial position.

The table below presents the activity of derivative risk management contracts:

Amount of Gain (Loss) Recognized on Risk Management Contracts

	Years Ended December 31,	
Location of Gain (Loss)	2024	2023
	(in millions)	
Operating Revenues	$ (23.9)	$ 24.5
Operation Expenses	0.2	0.1
Maintenance Expenses	—	(0.1)
Other Regulatory Assets (a)	2.8	(3.1)
Other Regulatory Liabilities (a)	13.4	7.8
Total Gain (Loss) on Risk Management Contracts (b)	$ (7.5)	$ 29.2

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment.

Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in the accounting guidance for "Derivatives and Hedging." Derivative contracts that have been designated as normal purchases or normal sales under that accounting guidance are not subject to MTM accounting treatment and are recognized on the statements of income on an accrual basis.

The accounting for the changes in the fair value of a derivative instrument depends on whether it qualifies for and has been designated as part of a hedging relationship and further, on the type of hedging relationship. Depending on the exposure, management designates a hedging instrument as a fair value hedge or a cash flow hedge.

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in revenues on a net basis on the statements of income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in revenues or expenses on the statements of income depending on the relevant facts and circumstances. Certain derivatives that economically hedge future commodity risk are recorded in the same line item on the statements of income as that of the associated risk being hedged. However, unrealized and some realized gains and losses for both trading and non-trading derivative instruments are recorded as regulatory assets (for losses) or regulatory liabilities (for gains) in accordance with the accounting guidance for "Regulated Operations."

Accounting for Cash Flow Hedging Strategies

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), I&M initially reports the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income on the balance sheets until the period the hedged item affects Net Income.

Realized gains and losses on derivative contracts for the purchase and sale of power designated as cash flow hedges are included in Operating Revenues or Operation Expenses on the statements of income or in Other Regulatory Assets or Other Regulatory Liabilities on the balance sheets, depending on the specific nature of the risk being hedged. During the years ended 2024 and 2023, I&M did not apply cash flow hedging to outstanding power derivatives.

I&M reclassifies gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income on the balance sheets into Interest on Long-term Debt on the statements of income in those periods in which hedged interest payments occur. During the year ended 2024, I&M did not apply cash flow hedging to outstanding interest rate derivatives. During the year ended 2023, I&M applied cash flow hedging to outstanding interest rate derivatives.

Cash flow hedges included in Accumulated Other Comprehensive Income on the balance sheets were:

Impact of Cash Flow Hedges on the Balance Sheets

December 31, 2024		December 31, 2023	
Interest Rate			
AOCI Gain (Loss) Net of Tax	Expected to be Reclassified to Net Income During the Next Twelve Months	AOCI Gain (Loss) Net of Tax	Expected to be Reclassified to Net Income During the Next Twelve Months
(in millions)			
$ (5.1)	$ (0.4)	$ (5.5)	$ (0.4)

The actual amounts reclassified from Accumulated Other Comprehensive Income to Net Income can differ from the estimate above due to market price changes.

Credit Risk

Management mitigates credit risk in wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. Management uses credit agency ratings and current market-based qualitative and quantitative data as well as financial statements to assess the financial health of counterparties on an ongoing basis.

Master agreements are typically used to facilitate the netting of cash flows associated with a single counterparty and may include collateral requirements. Collateral requirements in the form of cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. Some master agreements include margining, which requires a counterparty to post cash or letters of credit in the event exposure exceeds the established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with AEP's credit policy. In addition, master agreements allow for termination and liquidation of all positions in the event of a default including a failure or inability to post collateral when required.

10. FAIR VALUE MEASUREMENTS

Fair Value Measurements of Long-term Debt

The fair values of Long-term Debt are based on quoted market prices, without credit enhancements, for the same or similar issues and the current interest rates offered for instruments with similar maturities classified as Level 2 measurement inputs. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that could be realized in a current market exchange.

The book values and fair values of Long-term Debt are summarized in the following table:

December 31,			
2024		2023	
Book Value	Fair Value	Book Value	Fair Value
(in millions)			
$ 3,372.3	$ 3,005.9	$ 3,358.4	$ 3,125.4

Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal

Securities held in trust funds for decommissioning nuclear facilities and for the disposal of SNF are recorded at fair value. See "Nuclear Trust Funds" section of Note 1 for additional information.

The following is a summary of nuclear trust fund investments:

	December 31,							
	2024				2023			
	Fair Value	Gross Unrealized Gains	Gross Unrealized Losses	Other-Than-Temporary Impairments	Fair Value	Gross Unrealized Gains	Gross Unrealized Losses	Other-Than-Temporary Impairments
	(in millions)							
Cash and Cash Equivalents	$ 23.3	$ —	$ —	$ —	$ 16.8	$ —	$ —	$ —
Fixed Income Securities:								
United States Government	1,322.8	8.2	(5.3)	(20.2)	1,273.0	28.6	(3.9)	(33.2)
Corporate Debt	211.3	0.7	(9.8)	(5.8)	132.1	4.8	(5.2)	(8.6)
State and Local Government	—	—	—	—	1.7	—	—	—
Subtotal Fixed Income Securities	1,534.1	8.9	(15.1)	(26.0)	1,406.8	33.4	(9.1)	(41.8)
Equity Securities - Domestic	2,837.7	2,288.9	(0.4)	—	2,436.6	1,869.5	(0.9)	—
Other Special Funds	$ 4,395.1	$ 2,297.8	$ (15.5)	$ (26.0)	$ 3,860.2	$ 1,902.9	$ (10.0)	$ (41.8)

The following table provides the securities activity within the decommissioning and SNF trusts:

	Years Ended December 31,	
	2024	2023
	(in millions)	
Proceeds from Investment Sales	$ 2,851.2	$ 2,787.5
Purchases of Investments	2,902.4	2,845.1
Gross Realized Gains on Investment Sales	125.5	99.0
Gross Realized Losses on Investment Sales	11.5	26.6

The base cost of fixed income securities was $1.5 billion and $1.4 billion as of December 31, 2024 and 2023, respectively. The base cost of equity securities was $549 million and $568 million as of December 31, 2024 and 2023, respectively.
The fair value of fixed income securities held in the nuclear trust funds, summarized by contractual maturities, as of December 31, 2024 was as follows:

	Fair Value of Fixed Income Securities
	(in millions)
Within 1 year	$ 376.4
After 1 year through 5 years	598.8
After 5 years through 10 years	236.2
After 10 years	322.7
Total	$ 1,534.1

Fair Value Measurements of Financial Assets and Liabilities

For a discussion of fair value accounting and the classification of assets and liabilities within the fair value hierarchy, see the "Fair Value Measurements of Assets and Liabilities" section of Note 1.

The following tables set forth, by level within the fair value hierarchy, I&M's financial assets and liabilities that were accounted for at fair value on a recurring basis. As required by the accounting guidance for "Fair Value Measurements and Disclosures," financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in management's valuation techniques.

	December 31, 2024				
	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Derivative Instrument Assets					
Risk Management Commodity Contracts (b)	$ —	$ 19.9	$ 6.9	$ (8.4)	$ 18.4
Other Special Funds					
Cash and Cash Equivalents (c)	9.6	—	—	13.7	23.3
Fixed Income Securities:					
United States Government	—	1,322.8	—	—	1,322.8
Corporate Debt	—	211.3	—	—	211.3
State and Local Government	—	—	—	—	—
Subtotal Fixed Income Securities	—	1,534.1	—	—	1,534.1
Equity Securities - Domestic (a)	2,837.7	—	—	—	2,837.7
Total Other Special Funds	2,847.3	1,534.1	—	13.7	4,395.1
Total Assets	$ 2,847.3	$ 1,554.0	$ 6.9	$ 5.3	$ 4,413.5
Liabilities:					
Derivative Instrument Liabilities					
Risk Management Commodity Contracts (b)	$ —	$ 9.2	$ 0.5	$ (9.0)	$ 0.7

	December 31, 2023				
	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Derivative Instrument Assets					
Risk Management Commodity Contracts (b)	$ —	$ 37.4	$ 4.5	$ (2.3)	$ 39.6
Other Special Funds					
Cash and Cash Equivalents (c)	7.8	—	—	9.0	16.8
Fixed Income Securities:					
United States Government	—	1,273.0	—	—	1,273.0
Corporate Debt	—	132.1	—	—	132.1
State and Local Government	—	1.7	—	—	1.7
Subtotal Fixed Income Securities	—	1,406.8	—	—	1,406.8
Equity Securities - Domestic (a)	2,436.6	—	—	—	2,436.6
Total Other Special Funds	2,444.4	1,406.8	—	9.0	3,860.2
Total Assets	$ 2,444.4	$ 1,444.2	$ 4.5	$ 6.7	$ 3,899.8
Liabilities:					
Derivative Instrument Liabilities					
Risk Management Commodity Contracts (b)	$ —	$ 3.7	$ 1.7	$ (3.4)	$ 2.0

(a) Amounts represent publicly-traded equity securities and equity-based mutual funds.
(b) Amounts in "Other" column primarily represent counterparty netting of risk management and hedging contracts and associated cash collateral under the accounting guidance for "Derivatives and Hedging."
(c) Amounts in "Other" column primarily represent accrued interest receivables from financial institutions. Level 1 amounts primarily represent investments in money market funds.

The following tables set forth a reconciliation of changes in the fair value of net trading derivatives classified as Level 3 in the fair value hierarchy:

Year Ended December 31, 2024	Derivative Instrument Assets (Liabilities)
	(in millions)
Balance as of December 31, 2023	$ 2.8
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	7.3
Settlements	(10.0)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	6.3
Balance as of December 31, 2024	$ 6.4

Year Ended December 31, 2023	Derivative Instrument Assets (Liabilities)
	(in millions)
Balance as of December 31, 2022	$ 4.6
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	4.2
Settlements	(8.8)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	2.8
Balance as of December 31, 2023	$ 2.8

(a) Included in revenues on the statements of income.
(b) Represents the change in fair value between the beginning of the reporting period and the settlement of the risk management commodity contract.
(c) Relates to the net gains (losses) of those contracts that are not reflected on the statements of income. These changes in fair value are recorded as regulatory liabilities for net gains and as regulatory assets for net losses or accounts payable.

The following tables quantify the significant unobservable inputs used in developing the fair value of Level 3 positions:

December 31, 2024							
	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (b)
	(in millions)						
FTRs	$ 6.9	$ 0.5	Discounted Cash Flow	Forward Market Price	$ (4.07)	$ 9.32	$ 1.34

December 31, 2023							
	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (b)
	(in millions)						
FTRs	$ 4.5	$ 1.7	Discounted Cash Flow	Forward Market Price	$ (1.48)	$ 8.40	$ 0.85

(a) Represents market prices in dollars per MWh.
(b) The weighted-average is the product of the forward market price of the underlying commodity and volume weighted by term.

The following table provides the measurement uncertainty of fair value measurements to increases (decreases) in significant unobservable inputs related to FTRs for I&M as of December 31, 2024 and 2023:

Uncertainty of Fair Value Measurements

Significant Unobservable Input	Position	Change in Input	Impact on Fair Value Measurement
Forward Market Price	Buy	Increase (Decrease)	Higher (Lower)
Forward Market Price	Sell	Increase (Decrease)	Lower (Higher)

11. INCOME TAXES

Income Tax Expense (Benefit)

The details of I&M's Income Tax Expense (Benefit) as reported are as follows:

	Years Ended December 31,	
	2024	2023
	(in millions)	
Charged (Credited) to Operating Expenses, Net:		
Current	$ 38.0	$ 122.2
Deferred	(58.0)	(63.4)
Total	(20.0)	58.8
Charged (Credited) to Nonoperating Income, Net:		
Current	(14.3)	(8.1)
Deferred	(60.9)	7.6
Total	(75.2)	(0.5)
Total Income Tax Expense (Benefit)	$ (95.2)	$ 58.3

The following is a reconciliation of the difference between the amounts of federal income taxes computed by multiplying book income before income taxes by the federal statutory tax rate and the amount of income taxes reported:

	Years Ended December 31,	
	2024	2023
	(in millions)	
Net Income	$ 391.4	$ 335.9
Income Tax Expense (Benefit)	(95.2)	58.3
Pretax Income	$ 296.2	$ 394.2
Income Taxes on Pretax Income at Statutory Rate (21%)	$ 62.2	$ 82.8
Increase (Decrease) in Income Taxes Resulting from the Following Items:		
Reversal of Origination Flow-Through	4.0	6.4
Investment Tax Credit Amortization	(2.0)	(1.6)
Production Tax Credits	(69.0)	—
State and Local Income Taxes, Net	5.5	17.5
Removal Costs	(3.7)	(11.8)
AFUDC	(2.8)	(2.3)
Tax Reform Excess ADIT Reversal	(15.5)	(30.0)
Remeasurement of Excess ADIT	(73.3)	—
Federal Return-to-Provision	—	(2.5)
Other	(0.6)	(0.2)
Income Tax Expense (Benefit)	$ (95.2)	$ 58.3
Effective Income Tax Rate	(32.1)%	14.8 %

Net Deferred Tax Liability

The following table shows elements of I&M's net deferred tax liabilities and significant temporary differences. Amounts presented for 2023 were recast to allocate "Deferred State Income Taxes", and other miscellaneous temporary differences, amongst other categories to substantively reflect the elements of the net deferred tax liability.

	December 31,	
	2024	2023
	(in millions)	
Deferred Tax Assets	$ 1,072.2	$ 1,014.0
Deferred Tax Liabilities	(2,248.0)	(2,183.9)
Net Deferred Tax Liabilities	$ (1,175.8)	$ (1,169.9)
Property Related Temporary Differences	$ (189.9)	$ (315.6)
Amounts Due to Customers for Future Federal Income Taxes	73.1	103.2
Regulatory Assets	(49.2)	(27.7)
Accrued Nuclear Decommissioning	(1,052.2)	(923.5)
Tax Credit Carryforward	39.6	7.2
Operating Lease Liability	13.5	14.1
All Other, Net	(10.7)	(27.6)
Net Deferred Tax Liabilities	$ (1,175.8)	$ (1,169.9)

Federal and State Income Tax Audit Status

I&M and other AEP subsidiaries are not currently under IRS audit and the statute of limitations ("SOL") for the IRS to examine I&M and other AEP subsidiaries originally filed federal return has expired for tax years prior to 2017. I&M and other AEP subsidiaries agreed to extend the SOL on the 2017-2020 tax returns to May 31, 2025, to allow the Congressional Joint Committee on Taxation ("JCT") adequate time to complete its review of the now closed IRS audit. Following JCT's approval, I&M and other AEP subsidiaries received IRS confirmation that tax years 2017-2020 are now effectively closed as they only remain open for changes to other non-consolidated entities that I&M and other AEP subsidiaries hold an interest in.

I&M and other AEP subsidiaries file income tax returns in various state and local jurisdictions. I&M and other AEP subsidiaries are not currently under any state and local income tax examinations. Generally, the SOL have expired for tax years prior to 2017. In addition, management is monitoring and continues to evaluate the potential impact of federal legislation and corresponding state conformity.

Tax Credit Carryforward

Federal and state net income tax operating losses sustained in 2017, 2019 and 2021 resulted in unused federal and state income tax credits. As of December 31, 2024, I&M has federal tax credit carryforwards in the amount of $37.5 million. If these credits are not utilized, federal general business tax credits will expire in the years 2036 through 2041 and state tax credits will remain available indefinitely. Management anticipates future taxable income will be sufficient to realize the tax benefits of the state tax credits before they expire unused.

12. LEASES

I&M leases property, plant and equipment including, but not limited to, fleet, information technology and real estate leases. These leases require payments of non-lease components, including related property taxes, operating and maintenance costs. I&M does not separate non-lease components from associated lease components. Many of these leases have purchase or renewal options. Leases not renewed are often replaced by other leases. Options to renew or purchase a lease are included in the measurement of lease assets and liabilities if it is reasonably certain I&M will exercise the option.

Lease obligations are measured using the discount rate implicit in the lease when that rate is readily determinable. AEP has visibility into the rate implicit in the lease when assets are leased from selected financial institutions under master leasing agreements. When the implicit rate is not readily determinable, I&M measures its lease obligation using its estimated secured incremental borrowing rate. Incremental borrowing rates are comprised of an underlying risk-free rate and a secured credit spread relative to the lessee on a matched maturity basis.

Operating and Finance lease rental costs are generally charged to Operation Expense and Maintenance Expense in accordance with rate-making treatment for regulated operations. Lease costs associated with capital projects are included in Utility Plant on the balance sheets. For regulated operations with finance leases, a finance lease asset and offsetting liability are recorded at the present value of the remaining lease payments for each reporting period. The components of rental costs were as follows:

	Years Ended December 31,	
	2024	2023
	(in millions)	
Operating Lease Cost	$ 19.6	$ 19.6
Finance Lease Cost:		
Amortization of Right-of-Use Assets	108.1	98.3
Interest on Lease Liabilities	11.9	9.0
Total Lease Rental Costs (a)	$ 139.6	$ 126.9

(a) Excludes variable and short-term lease costs, which were immaterial.

Supplemental information related to leases are shown in the tables below:

	December 31,	
	2024	2023
	(in millions)	
Weighted-Average Remaining Lease Term (years):		
Operating Leases	4.43	4.53
Finance Leases	4.83	4.95
Weighted-Average Discount Rate:		
Operating Leases	4.11 %	3.89 %
Finance Leases	9.07 %	8.62 %

	Years Ended December 31,	
	2024	2023
	(in millions)	
Cash paid for amounts included in the measurement of lease liabilities:		
Operating Cash Flows from Operating Leases	$ 19.6	$ 19.5
Operating Cash Flows from Finance Leases	119.9	107.3
Non-cash Acquisitions Under Operating Leases	$ 15.0	$ 7.9

The following tables show property, plant and equipment under finance leases, operating leases and related obligations recorded on I&M's balance sheets. Lease obligations are not recognized on the balance sheets for lease agreements with a lease term of less than twelve months.

	December 31,	
	2024	2023
	(in millions)	
Property, Plant and Equipment Under Finance Leases:		
Utility Plant (a)	$ 22.0	$ 31.5
Nuclear Fuel Under Finance Leases (b)	132.3	153.8
Net Property, Plant and Equipment Under Finance Leases	$ 154.3	$ 185.3
Obligations Under Finance Leases:		
Noncurrent	$ 79.5	$ 102.5
Current	74.8	82.8
Total Obligations Under Finance Leases	$ 154.3	$ 185.3

(a) Includes $33 million and $39 million of accumulated provision for depreciation and amortization for the years ended December 31, 2024 and 2023, respectively.
(b) Includes $296 million and $254 million of accumulated provision for depreciation and amortization for the years ended December 31, 2024 and 2023, respectively.

	December 31,	
	2024	2023
	(in millions)	
Property, Plant and Equipment Under Operating Leases:		
Utility Plant (a)	$ 36.3	$ 37.9
Nonutility Plant	27.2	32.6
Accumulated Provision for Depreciation and Amortization - Nonutility Plant	(12.0)	(16.6)
Net Property, Plant and Equipment Under Operating Leases	$ 51.5	$ 53.9
Obligations Under Operating Leases:		
Noncurrent	$ 40.1	$ 37.7
Current	12.3	16.8
Total Obligations Under Operating Leases	$ 52.4	$ 54.5

(a) Includes $28 million and $26 million of accumulated provision for depreciation and amortization for the years ended December 31, 2024 and 2023, respectively.

Future minimum lease payments consisted of the following as of December 31, 2024:

	Finance Leases	Operating Leases
	(in millions)	
2025	$ 92.7	$ 15.9
2026	51.1	15.0
2027	18.6	11.0
2028	10.0	9.0
2029	2.8	4.3
After 2029	4.7	2.5
Total Future Minimum Lease Payments	179.9	57.7
Less: Imputed Interest	25.6	5.3
Estimated Present Value of Future Minimum Lease Payments	$ 154.3	$ 52.4

Master Lease Agreements

I&M leases certain equipment under master lease agreements. Under the lease agreements, the lessor is guaranteed a residual value up to a stated percentage of the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, I&M is committed to pay the difference between the actual fair value and the residual value guarantee. Historically, at the end of the lease term the fair value has been in excess of the amount guaranteed. As of December 31, 2024, the maximum potential loss by I&M for these lease agreements assuming the fair value of the equipment is zero at the end of the lease term was $4 million.

Lessor Activity

I&M's lessor activity was immaterial as of and for the twelve months ended December 31, 2024 and December 31, 2023, respectively.

Nuclear Fuel Lease

In November 2019, I&M entered into a sale-and-leaseback transaction for $61 million with DCC Fuel XIV LLC (DCC XIV). DCC XIV is a single-lessee leasing arrangement with one asset and was formed for the sole purpose of acquiring, owning and leasing nuclear fuel to I&M. The lease has a variable rate and is a finance lease with a term of 54 months. I&M makes payments on the lease monthly. I&M made the final payment in May 2024.
In October 2020, I&M entered into a sale-and-leaseback transaction for $70 million with DCC Fuel XV LLC (DCC XV). DCC XV is a single-lessee leasing arrangement with one asset and was formed for the sole purpose of acquiring, owning and leasing nuclear fuel to I&M. The lease has a variable rate and is a finance lease with a term of 54 months. I&M makes payments on the lease monthly. Payments began in November 2020.

In May 2021, I&M entered into a sale-and-leaseback transaction for $65 million with DCC Fuel XVI LLC (DCC XVI). DCC XVI is a single-lessee leasing arrangement with one asset and was formed for the sole purpose of acquiring, owning and leasing nuclear fuel to I&M. The lease has a fixed 0.93% rate and is a finance lease with a term of 54 months. I&M makes payments on the lease monthly. Payments began in June 2021.

In May 2022, I&M entered into a sale-and-leaseback transaction for $73 million with DCC Fuel XVII LLC (DCC XVII). DCC XVII is a single-lessee leasing arrangement with one asset and was formed for the sole purpose of acquiring, owning and leasing nuclear fuel to I&M. The lease has a fixed 3.44% rate and is a finance lease with a term of 54 months. I&M makes payments on the lease monthly. Payments began in June 2022.

In November 2022, I&M entered into a sale-and-leaseback transaction for $70 million with DCC Fuel XVIII LLC (DCC XVIII). DCC XVIII is a single-lessee leasing arrangement with one asset and was formed for the sole purpose of acquiring, owning and leasing nuclear fuel to I&M. The lease has a fixed 5.93% rate and is a finance lease with a term of 54 months. I&M makes payments on the lease monthly. Payments began in December 2022.

In November 2023, I&M entered into a sale-and-leaseback transaction for $70 million with DCC Fuel XIX LLC (DCC XIX). DCC XIX is a single-lessee leasing arrangement with one asset and was formed for the sole purpose of acquiring, owning and leasing nuclear fuel to I&M. The lease has a fixed 6.01% rate and is a finance lease with a term of 54 months. I&M makes payments on the lease monthly. Payments began in December 2023.

In April 2024, I&M entered into a sale-and-leaseback transaction for $80 million with DCC Fuel XX LLC (DCC XX). DCC XX is a single-lessee leasing arrangement with one asset and was formed for the sole purpose of acquiring, owning and leasing nuclear fuel to I&M. The lease has a fixed 6.41% rate and is a finance lease with a term of 54 months. I&M makes payments on the lease monthly. Payments began in May 2024.

13. VOLUNTARY SEVERANCE PROGRAM

In April 2024, management announced a voluntary severance program designed to achieve a reduction in the size of AEP's workforce. Approximately 7,400 of AEP's 16,800 employees were eligible to participate in the program. Approximately 1,000 employees chose to take the voluntary severance package and substantially all terminated employment in July 2024. The severance program provides two weeks of base pay for every year of service with a minimum of four weeks and a maximum of 52 weeks of base pay. Certain positions impacted by the voluntary severance program have been and will continue to be refilled to maintain safe, effective and efficient operations. Net savings from the program will help offset increasing operating expenses and high interest costs in order to keep electricity costs affordable for customers.

I&M recorded a $15 million charge to expense in the second quarter of 2024 related to this voluntary severance program. As of December 31, 2024, there was an immaterial remaining balance to be paid.

These expenses were primarily included in Operating Expenses on the statements of income and Miscellaneous Current and Accrued Liabilities on the balance sheets. Settlement accounting was triggered for the qualified pension plan in November 2024 under the accounting guidance for "Compensation - Retirement Benefits". A settlement charge of $90 million was recorded. AEP will seek recovery for the portion of the expense related to regulated operations. See Note 7 - Benefit Plans for additional information associated with the plan.

14. FINANCING ACTIVITIES

Long-term Debt

The following table details long-term debt outstanding:

	Maturity	Weighted-Average Interest Rate as of December 31, 2024	Interest Rate Ranges as of December 31, 2024	Interest Rate Ranges as of December 31, 2023	Outstanding as of December 31, 2024	Outstanding as of December 31, 2023
Senior Unsecured Notes	2028-2053	4.52%	3.25%-6.05%	3.25%-6.05%	$ 2,875.0	$ 2,875.0
Pollution Control Bonds (a)	2025 (b)	2.49%	0.75%-3.05%	0.75%-3.05%	190.0	190.0
Spent Nuclear Fuel Obligation (c)					316.3	300.4
Other Long-term Debt	2025	6.00%	6.00%	6.00%	0.2	2.7
Unamortized Discount, Net					(9.2)	(9.7)
Total Long-term Debt Outstanding					$ 3,372.3	$ 3,358.4

(a) For certain series of Pollution Control Bonds, interest rates are subject to periodic adjustment. Certain series may be purchased on demand at periodic interest adjustment dates. Letters of credit from banks and insurance policies support certain series.
(b) Certain Pollution Control Bonds are subject to redemption earlier than the maturity date.
(c) Spent Nuclear Fuel Obligation consists of a liability along with accrued interest for disposal of SNF. See "Spent Nuclear Fuel Disposal" section of Note 6 for additional information.

As of December 31, 2024, outstanding long-term debt was payable as follows:

	(in millions)
2025	$ 190.2
2026	—
2027	—
2028	350.0
2029	—
After 2029	2,841.3
Principal Amount	3,381.5
Unamortized Discount	(9.2)
Total Long-term Debt	$ 3,372.3

Dividend Restrictions

I&M pays dividends to Parent provided funds are legally available. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of I&M to transfer funds to Parent in the form of dividends.

All of the dividends declared by I&M are subject to a Federal Power Act restriction that prohibits the payment of dividends out of capital accounts in certain circumstances; payment of dividends is generally allowed out of retained earnings. However, the Federal Power Act creates a reserve on earnings attributable to hydroelectric generation plants. Because of their ownership of such plants, this reserve applies to I&M.

I&M has credit agreements that contain covenants that limit their debt to capitalization ratio to 67.5%. The method for calculating outstanding debt and capitalization is contractually-defined in the credit agreements.

The most restrictive dividend limitation for I&M is through the credit agreements. As of December 31, 2024, the maximum amount of restricted net assets of I&M that may not be distributed to the Parent in the form of a loan, advance or dividend was $1.8 billion.
The Federal Power Act restriction limits the ability of I&M to pay dividends out of retained earnings because of their ownership in hydroelectric generation. Additionally, the credit agreement covenant restrictions can limit the ability of I&M to pay dividends out of retained earnings. As of December 31, 2024, the amount of any such restrictions was $707 million.

Corporate Borrowing Program

I&M uses a corporate borrowing program to meet its short-term borrowing needs. The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries. The AEP Utility Money Pool operates in accordance with the terms and conditions of its agreement filed with the FERC. The amounts of outstanding borrowings from the Utility Money Pool as of December 31, 2024 and 2023 are included in Notes Payable to Associated Companies on the balance sheets. I&M's money pool activity and corresponding authorized borrowing limits are described in the following table:

Years ended December 31,	Maximum Borrowings from the Utility Money Pool	Maximum Loans to the Utility Money Pool	Average Borrowings from the Utility Money Pool	Average Loans to the Utility Money Pool	Borrowings from the Utility Money Pool as of December 31,	Authorized Short-term Borrowing Limit
			(in millions)			
2024	$ 135.8	$ 8.4	$ 58.8	$ 3.9	$ 126.8	$ 500.0
2023	475.3	112.2	149.0	44.9	63.3	500.0

The maximum, minimum and average interest rates for funds either borrowed from or loaned to the Utility Money Pool are summarized in the following table:

Years ended December 31,	Maximum Interest Rates for Funds Borrowed from the Utility Money Pool	Minimum Interest Rates for Funds Borrowed from the Utility Money Pool	Maximum Interest Rates for Funds Loaned to the Utility Money Pool	Minimum Interest Rates for Funds Loaned to the Utility Money Pool	Average Interest Rates for Funds Borrowed from the Utility Money Pool	Average Interest Rates for Funds Loaned to the Utility Money Pool
2024	5.79 %	4.74 %	5.68 %	5.14 %	5.40 %	5.44 %
2023	5.77 %	4.66 %	5.81 %	5.33 %	5.14 %	5.65 %

Interest expense and interest income related to the Utility Money Pool financing relationship are included in Interest on Debt to Associated Companies and Interest and Dividend Income, respectively, on the statements of income. The interest expense related to the corporate borrowing programs were $4 million and $3 million for the years ended December 31, 2024 and 2023, respectively, and interest income related to the corporate borrowing programs were $6 thousand and $0 for the years ended December 31, 2024 and 2023, respectively.

Securitized Accounts Receivables – AEP Credit

Under this sale of receivables arrangement, I&M sells, without recourse, certain of its customer accounts receivable and accrued utility revenue balances to AEP Credit and is charged a fee based on AEP Credit's financing costs, administrative costs and uncollectible accounts experience for I&M's receivables. The costs of customer accounts receivable sold are reported in Other Deductions on I&M's statements of income. I&M manages and services its customer accounts receivable, which are sold to AEP Credit. AEP Credit securitizes the eligible receivables for I&M and retains the remainder.

The amount of accounts receivable and accrued utility revenues under the sale of receivables agreement as of December 31, 2024 and 2023 were $161 million and $156 million, respectively.

The fees paid to AEP Credit for customer accounts receivable sold were $15 million and $16 million for the years ended December 31, 2024 and 2023, respectively.

The proceeds on the sale of receivables to AEP Credit were $2.1 billion and $2.1 billion for the years ended December 31, 2024 and 2023, respectively.

15. RELATED PARTY TRANSACTIONS

For other related party transactions, also see "Income Taxes and Investment and Production Tax Credits" section of Note 1 in addition to "Corporate Borrowing Program" and "Securitized Accounts Receivables – AEP Credit" sections of Note 13.

Intercompany Billings

I&M performs certain utility services for each other when necessary or practical. The costs of these services are billed on a direct-charge basis, whenever possible, or on reasonable basis of proration for services that benefit multiple companies. The billings for services are made at cost and include no compensation for the use of equity capital.

Power Coordination Agreement

Effective January 1, 2014, the FERC approved the PCA. Under the PCA, APCo, I&M, KPCo and WPCo are individually responsible for planning their respective capacity obligations. The PCA allows, but does not obligate, APCo, I&M, KPCo and WPCo to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective Off-system Sales and purchase activities.

AEPSC conducts power, capacity, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other risk management activities on behalf of APCo, I&M, KPCo and WPCo. Certain power and natural gas risk management activities for APCo, I&M, KPCo and WPCo are allocated based on the four member companies' respective equity positions.

Joint License Agreement

AEPTCo entered into a 50-year joint license agreement with APCo, I&M, KPCo, OPCo and PSO, respectively, allowing either party to occupy the granting party's facilities or real property. In addition, AEPTCo entered into a 5-year joint license agreement with APCo and WPCo. After the expiration of these agreements, the term shall automatically renew for successive one-year terms unless either party provides notice. The joint license billing provides compensation to the granting party for the cost of carrying assets, including depreciation expense, property taxes, interest expense, return on equity and income taxes. AEPTCo recorded the costs related to these agreements in Operation Expense on the statements of income. I&M recorded income related to these agreements in Operating Revenues on the statements of income. The impact of the joint license agreement for the years ended December 31, 2024 and 2023 was not material.

Unit Power Agreements

A UPA between AEGCo and I&M (the I&M Power Agreement) provides for the sale by AEGCo to I&M of all the energy and capacity available to AEGCo at the Rockport Plant unless it is sold to another utility. I&M is obligated, whether or not power is available from AEGCo, to pay as a demand charge for the right to receive such power (and as an energy charge for any associated energy taken by I&M) net of amounts received by AEGCo from any other sources, sufficient to enable AEGCo to pay all of its operating and other expenses, including a rate of return on the common equity of AEGCo as approved by the FERC. The UPA will continue in effect until the debt obligations of AEGCo secured by the Rockport Plant have been satisfied and discharged (currently expected to be December 2028). I&M's direct purchases from AEGCo were $209 million and $181 million for the years ended December 31, 2024 and 2023, respectively. These direct purchases are presented as Operation Expense on I&M's statements of income.

Sales and Purchases of Property

Certain AEP subsidiaries had affiliated sales and purchases of electric property individually amounting to $100 thousand or more, sales and purchases of meters and transformers, and sales and purchases of transmission property. There were no gains or losses recorded on the transactions and the net book value of all sales and purchases for the years ended December 31, 2024 and 2023 were not material. These sales and purchases are recorded in Utility Plant on the balance sheets.

Charitable Contributions to AEP Foundation

The American Electric Power Foundation is funded by American Electric Power and its utility operating units. The Foundation provides a permanent, ongoing resource for charitable initiatives and multi-year commitments in the communities served by AEP and initiatives outside of AEP's 11-state service area. Charitable contributions to the AEP Foundation were not made in 2024 or 2023.

Other Related Party Contributions

For the years ended December 31, 2023 and 2022, AEP made contributions of $0.1 million and $0.2 million, respectively, to Clean Affordable Reliable Coalition (CARE), a 501(c)(6) organization established to encourage communication, discussion and concerted action related to tax policy associated with clean, affordable and reliable power initiatives. These contributions were made in the ordinary course of business. AEP was a member of CARE and provided the organization its primary financial support. In addition, an employee of AEP served as a board member of the organization during 2023 and 2022. AEP management has determined these contributions are Related Party transactions under ASC 850 based on AEP's ability to significantly influence the management and operating policies of CARE. I&M made no contributions to CARE in 2024.

Beginning in August 2024, an officer of AEP also served as a member of the board of directors of a company that is a vendor of I&M. From August 2024 through December 2024, I&M purchased $1.5 million of distribution and transmission infrastructure services from the related party vendor in the ordinary course of business.

I&M Barging, Urea Transloading and Other Services

I&M provides barging, urea transloading and other transportation services to affiliates. Urea is a chemical used to control NOx emissions at certain generation plants in the AEP System. I&M recorded revenues from barging, transloading and other services of $65 million and $59 million for the years ended December 31, 2024 and 2023, respectively, in Operating Revenues on the statements of income.

AEP Wind Holdings LLC PPAs

Prior to acquisition, Fowler Ridge 2 had PPAs with I&M and OPCo for a portion of their energy production. The I&M portion totaled $8 million for the year ended December 31, 2023 of purchased electricity.

Transmission Service Charges

The AEP East Companies are parties to the TA, which defines how transmission costs through the PJM OATT are allocated among the AEP East Companies on a 12-month average coincident peak basis. Additional costs for transmission services provided by AEPTCo and other transmission affiliates are billed to AEP East Companies through the PJM OATT. I&M recorded the net transmission service charges of $253 million and $226 million, for the years ended December 31, 2024 and 2023, respectively, in Operation Expense on the statements of income.

Affiliated Revenues

The following table shows the revenues derived from direct sales to affiliates, auction sales to affiliates, net transmission agreement sales and other revenues for the years ended December 31, 2024 and 2023:

	Years Ended December 31,	
Related Party Revenues	2024	2023
	(in millions)	
Transmission Revenues	$ (8.8)	$ (11.1)
Barging, Urea Transloading and Other Transportation Services	—	59.0
Other Revenues	75.0	9.9

16. PROPERTY, PLANT AND EQUIPMENT

Depreciation

I&M provides for depreciation of Utility Plant, on a straight-line basis over the estimated useful lives of property, generally using composite rates by functional class. The following table provides total regulated annual composite depreciation rates by functional class:

Year	Nuclear	Steam	Other Generation	Hydro	Transmission	Distribution	General
				(in percentages)			
2024	4.2 %	7.3 %	4.3 %	4.7 %	2.6 %	2.8 %	8.9 %
2023	3.9 %	7.4 %	5.1 %	3.6 %	2.5 %	2.9 %	9.1 %

The composite depreciation rate generally includes a component for non-ARO removal costs, which is credited to accumulated depreciation on the balance sheets. Actual removal costs incurred are charged to accumulated depreciation.

Asset Retirement Obligations

Listed below are significant changes to I&M's ARO balances as of December 31, 2024 and 2023:

- In April 2024, the Federal EPA finalized revisions to the CCR Rule to expand the scope of the rule to include inactive impoundments at inactive facilities as well as to establish requirements for currently exempt solid waste management units that involve the direct placement of CCR on the land. In the second quarter of 2024, AEP evaluated the applicability of the rule to current and former plant sites and incurred ARO liabilities of $602 million and revised cash flow estimates by an additional $72 million based on initial cost estimates. See the "Federal EPA's Revised CCR Rule" section of Note 6 for additional information.
- In December 2024, I&M recorded a $176 million revision as a result of the completion of the latest Cook Plant nuclear decommissioning study. I&M's ARO related to nuclear decommissioning costs for the Cook Plant was $1.97 billion and $2.11 billion as of December 31, 2024 and 2023. As of December 31, 2024 and 2023, the fair value of I&M's assets that are legally restricted for purposes of settling decommissioning liabilities totaled $4.03 billion and $3.51 billion, respectively. These assets are included in Spent Nuclear Fuel and Decommissioning Trusts on I&M's balance sheets.

The following is a reconciliation of the 2024 and 2023 aggregate carrying amounts of ARO:

Year	ARO at January 1,	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates (a)	ARO at December 31,	
			(in millions)				
2024	$ 2,105.9	$ 80.2	$ 85.7	$ (2.2)	$ (175.9)	$ 2,093.7	(b)(c)(d)
2023	2,028.1	74.8	4.8	(3.7)	1.9	2,105.9	(b)(c)(d)

(a) Unless discussed above, primarily related to ash ponds, landfills and mine reclamation, generally due to changes in estimated closure area, volumes and/or unit costs.
(b) Includes ARO related to ash disposal facilities.
(c) Includes ARO related to nuclear decommissioning costs for the Cook Plant.
(d) Includes ARO related to asbestos removal.

Jointly-owned Electric Facilities

I&M as electric facilities that are jointly-owned with affiliated companies. Using its own financing, I&M is obligated to pay its share of the costs of these jointly-owned facilities in the same proportion as its ownership interest. I&M's proportionate share of the operating costs associated with these facilities is included in its statements of income and the investments and accumulated depreciation are reflected in its balance sheets under Utility Plant as follows:

			Share as of December 31, 2024		
	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
			(in millions)		
Rockport Generating Plant (a)(b)	Coal	50.0 %	$ 1,345.0	$ 10.9	$ 1,181.8

			Share as of December 31, 2023		
	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
			(in millions)		
Rockport Generating Plant (a)(b)	Coal	50.0 %	$ 1,341.4	$ 7.9	$ 1,018.9

(a) Operated by I&M.
(b) AEGCo owns 50%.

17. REVENUE FROM CONTRACTS WITH CUSTOMERS

Disaggregated Revenues from Contracts with Customers

The table below represents revenues from contracts with customers, net of respective provisions for refund, by type of revenue for I&M.

	Years Ended December 31,	
	2024	2023
	(in millions)	
Retail Revenues:		
Residential Revenues	$ 849.6	$ 827.5
Commercial Revenues	607.5	560.4
Industrial Revenues	599.8	587.5
Other Retail Revenues	5.1	5.0
Total Retail Revenues	$ 2,062.0	$ 1,980.4
Wholesale Revenues:		
Generation Revenues	277.3	245.2
Transmission Revenues (a)	40.6	38.6
Total Wholesale Revenues	317.9	283.8
Other Revenues from Contracts with Customers (a)	69.5	27.6
Total Revenues from Contracts with Customers	2,449.4	2,291.8
Other Revenues:		
Alternative Revenues	(7.6)	(10.9)
Other Revenues	(23.9)	24.3
Total Other Revenues	(31.5)	13.4
Total Operating Revenues	$ 2,417.9	$ 2,305.2

(a) Amounts include affiliated and nonaffiliated revenues.

Performance Obligations

I&M has performance obligations as part of its normal course of business. A performance obligation is a promise to transfer a distinct good or service, or a series of distinct goods or services that are substantially the same and have the same pattern of transfer to a customer. The invoice practical expedient within the accounting guidance for "Revenue from Contracts with Customers" allows for the recognition of revenue from performance obligations in the amount of consideration to which there is a right to invoice the customer and when the amount for which there is a right to invoice corresponds directly to the value transferred to the customer.

The purpose of the invoice practical expedient is to depict an entity's measure of progress toward completion of the performance obligation within a contract and can only be applied to performance obligations that are satisfied over time and when the invoice is representative of services provided to date. I&M elected to apply the invoice practical expedient to recognize revenue for performance obligations satisfied over time as the invoices from the respective revenue streams are representative of services or goods provided to date to the customer. Performance obligations for I&M are summarized as follows:

Retail Revenues

I&M has performance obligations to generate, transmit and distribute electricity for sale to rate-regulated retail customers. The performance obligation to deliver electricity is satisfied over time as the customer simultaneously receives and consumes the benefits provided. Revenues are variable as they are subject to the customer's usage requirements.

Rate-regulated retail customers typically have the right to discontinue receiving service at will, therefore these contracts between I&M and their customers for rate-regulated services are generally limited to the services requested and received to date for such arrangements. Retail customers are generally billed on a monthly basis, and payment is typically due within 15 to 20 days after the issuance of the invoice.

Wholesale Revenues - Generation

I&M has performance obligations to sell electricity to wholesale customers from generation assets in PJM. The performance obligation to deliver electricity from generation assets is satisfied over time as the customer simultaneously receives and consumes the benefits provided. Wholesale generation revenues are variable as they are subject to the customer's usage requirements.

I&M also has performance obligations to stand ready in order to promote grid reliability. Stand ready services are sold into PJM's RPM capacity market. RPM entails a base auction and at least three incremental auctions for a specific PJM delivery year, with the incremental auctions spanning three years. The performance obligation to stand ready is satisfied over time and the consideration for which is variable until the occurrence of the final incremental auction, at which point the performance obligation becomes fixed.

Payments from the RTO for stand ready services are typically received within one week from the issuance of the invoice, which is typically issued weekly. Gross margin resulting from generation sales are primarily subject to margin sharing agreements with customers and vary by state, where the revenues are reflected gross in the disaggregated revenues table above.

Wholesale Revenues - Transmission

I&M has performance obligations to transmit electricity to wholesale customers through assets owned and operated. The performance obligation to provide transmission services in PJM is partially fixed for a period of one year or less. Payments from the RTO for transmission services are typically received within one week from the issuance of the invoice, which is issued weekly for PJM.

I&M collects revenues through transmission formula rates. The FERC-approved rates establish the annual transmission revenue requirement (ATRR) and transmission service rates for transmission owners. The formula rates establish rates for a one year period and also include a true-up calculation for the prior year's billings, allowing for over/under-recovery of the transmission owner's ATRR. The annual true-ups meet the definition of alternative revenues in accordance with the accounting guidance for "Regulated Operations," and are therefore presented as such in the disaggregated revenues table above.

The AEP East Companies are parties to the TA, which defines how transmission costs are allocated among the AEP East Companies on a 12-month average coincident peak basis. Affiliate revenues as a result of the TA are reflected as Transmission Revenues in the disaggregated revenues table above.

Fixed Performance Obligations

The following table represents the remaining fixed performance obligations satisfied over time as of December 31, 2024. Fixed performance obligations primarily include electricity sales for fixed amounts of energy and stand ready services into PJM's RPM market. I&M elected to apply the exemption to not disclose the value of unsatisfied performance obligations for contracts with an original expected term of one year or less. Due to the annual establishment of revenue requirements, transmission revenues are excluded from the table below. I&M amounts shown in the table below include affiliated and nonaffiliated revenues.

2025	2026-2027	2028-2029	After 2029	Total
		(in millions)		
$ 4.4	$ 8.8	$ 6.8	$ 2.4	$ 22.4

Contract Assets and Liabilities

Contract assets are recognized when I&M has a right to consideration that is conditional upon the occurrence of an event other than the passage of time, such as future performance under a contract. I&M did not have any material contract assets as of December 31, 2024 and 2023.

When I&M receives consideration, or such consideration is unconditionally due from a customer prior to transferring goods or services to the customer under the terms of a sales contract, they recognize a contract liability on the balance sheets in the amount of that consideration. Revenue for such consideration is subsequently recognized in the period or periods in which the remaining performance obligations in the contract are satisfied. I&M's contract liabilities typically arise from services provided under joint use agreements for utility poles. I&M did not have any material contract liabilities as of December 31, 2024 and 2023.

Accounts Receivable from Contracts with Customers

Accounts receivable from contracts with customers are presented on I&M's balance sheets within the Customer Accounts Receivable line item. I&M's balances for receivables from contracts that are not recognized in accordance with the accounting guidance for "Revenue from Contracts with Customers" included in Customer Accounts Receivable were not material as of December 31, 2024 and 2023. See "Securitized Accounts Receivable - AEP Credit" section of Note 14 for additional information.

The amount of affiliated accounts receivable from contracts with customers included in Accounts Receivable from Associated Companies on I&M's balance sheets were $55 million and $44 million, as of December 31, 2024 and 2023.

Contract Costs

Contract costs to obtain or fulfill a contract are accounted for under the guidance for "Other Assets and Deferred Costs" and presented as a single asset and are neither bifurcated nor reclassified between current assets and deferred debits on the balance sheets. Contract costs to acquire a contract are amortized in a manner consistent with the transfer of goods or services to the customer in Operation Expenses on the statements of income. I&M did not have material contract costs as of December 31, 2024 and 2023.

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available-For-Sale Securities (b)	Minimum Pension Liability Adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 116, Line 78) (i)	Total Comprehensive Income (j)
1	Balance of Account 219 at Beginning of Preceding Year				4,682,507	(4,970,496)		(287,989)		
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income				(889,320)	(353,077)		(1,242,397)		
3	Preceding Quarter/Year to Date Changes in Fair Value				941,879			941,879		
4	Total (lines 2 and 3)				52,559	(353,077)		(300,518)	335,873,067	335,572,549
5	Balance of Account 219 at End of Preceding Quarter/Year				4,735,066	(5,323,573)		(588,507)		
6	Balance of Account 219 at Beginning of Current Year				4,735,066	(5,323,573)		(588,507)		
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income				8,878,889	436,882		9,315,771		
8	Current Quarter/Year to Date Changes in Fair Value				(8,399,715)			(8,399,715)		
9	Total (lines 7 and 8)				479,174	436,882		916,056	391,365,619	392,281,675
10	Balance of Account 219 at End of Current Quarter/Year				5,214,240	(4,886,691)		327,549		

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company For the Current Year/Quarter Ended (b)	Electric (c)	Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)
1	UTILITY PLANT							
2	In Service							
3	Plant in Service (Classified)	10,924,760,850	10,924,760,850					
4	Property Under Capital Leases	58,329,476	58,329,476					
5	Plant Purchased or Sold							
6	Completed Construction not Classified	635,678,946	635,678,946					
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	11,618,769,272	11,618,769,272					
9	Leased to Others							
10	Held for Future Use	1,320,294	1,320,294					
11	Construction Work in Progress	336,778,473	336,778,473					
12	Acquisition Adjustments							
13	Total Utility Plant (8 thru 12)	11,956,868,039	11,956,868,039					
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	4,633,719,857	4,633,719,857					
15	Net Utility Plant (13 less 14)	7,323,148,182	7,323,148,182					
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	4,368,320,888	4,368,320,888					
19	Amortization and Depletion of Producing Natural Gas Land and Land Rights							
20	Amortization of Underground Storage Land and Land Rights							
21	Amortization of Other Utility Plant	265,393,727	265,393,727					
22	Total in Service (18 thru 21)	4,633,714,615	4,633,714,615					
23	Leased to Others							
24	Depreciation							
25	Amortization and Depletion							
26	Total Leased to Others (24 & 25)							
27	Held for Future Use							
28	Depreciation	5,242	5,242					
29	Amortization							
30	Total Held for Future Use (28 & 29)	5,242	5,242					
31	Abandonment of Leases (Natural Gas)							
32	Amortization of Plant Acquisition Adjustment							
33	Total Accum Prov (equals 14) (22,26,30,31,32)	4,633,719,857	4,633,719,857					

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)	Changes during Year Amortization (d)	Changes during Year Other Reductions (Explain in a footnote) (e)	Balance End of Year (f)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)					
2	Fabrication					
3	Nuclear Materials	78,607,966	137,265,440		[c]79,679,744	136,193,662
4	Allowance for Funds Used during Construction	4,787,830	4,972,921		[d]2,668,292	7,092,459
5	(Other Overhead Construction Costs, provide details in footnote)					
6	SUBTOTAL (Total 2 thru 5)	83,395,796				143,286,121
7	Nuclear Fuel Materials and Assemblies					
8	In Stock (120.2)					
9	In Reactor (120.3)	2,558,943	82,123,286		[e]80,360,000	4,322,229
10	SUBTOTAL (Total 8 & 9)	2,558,943				4,322,229
11	Spent Nuclear Fuel (120.4)	580,843,929	60,724,750		[f]217,891,681	423,676,998
12	Nuclear Fuel Under Capital Leases (120.6)	[a]153,808,147	[b]80,360,000	101,905,100		[b]132,263,047
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	582,317,204		(1,021,130)	[g]157,391,681	425,946,653
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	238,289,611				277,601,742
15	Estimated Net Salvage Value of Nuclear Materials in Line 9					
16	Estimated Net Salvage Value of Nuclear Materials in Line 11					
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing					
18	Nuclear Materials held for Sale (157)					
19	Uranium					
20	Plutonium					
21	Other (Provide details in footnote)					
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)					

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: NuclearFuelUnderCapitalLeases
Includes 2023 costs in connection with nuclear leases: Finance charges - $6,471,425
(b) Concept: NuclearFuelUnderCapitalLeasesAdditions
Reclassification of nuclear fuel from owned to leased due to sale/leaseback with third party - $ 80,360,000
(c) Concept: NuclearMaterialsNuclearFuelInProcessOfRefinementConversionEnrichmentAndFabricationOtherReductions
Placed nuclear fuel into reactor
(d) Concept: AllowanceForFundsConstructionNuclearFuelInProcessOfRefinementConversionEnrichmentAndFabricationOtherReductions
Placed nuclear fuel into reactor
(e) Concept: NuclearFuelAssembliesInReactorOtherReductions
Reclassification of nuclear fuel from owned to leased due to sale/leaseback with third party - $ 80,360,000
(f) Concept: SpentNuclearFuelOtherReductions
Retirement of spent fuel
(g) Concept: AccumulatedProvisionForAmortizationOfNuclearFuelAssembliesOtherReductions
Retirement of spent fuel
(h) Concept: NuclearFuelUnderCapitalLeases
Includes 2024 costs in connection with nuclear leases: Finance charges - $9,493,857

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of the prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.
7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.
8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.
9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date.

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
1	1. INTANGIBLE PLANT						
2	(301) Organization	117,425					117,425
3	(302) Franchise and Consents	19,866,098					19,866,098
4	(303) Miscellaneous Intangible Plant	344,865,061	33,926,882	33,087,169			345,704,774
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	364,848,584	33,926,882	33,087,169			365,688,297
6	2. PRODUCTION PLANT						
7	A. Steam Production Plant						
8	(310) Land and Land Rights	7,407,266					7,407,266
9	(311) Structures and Improvements	133,021,604	(14,923,438)	66,279			118,031,887
10	(312) Boiler Plant Equipment	919,692,727	688,055	413,245			919,967,537
11	(313) Engines and Engine-Driven Generators						
12	(314) Turbogenerator Units	121,219,353	407,123	171,875			121,454,601
13	(315) Accessory Electric Equipment	63,331,063	119,250	14,064			63,436,249
14	(316) Misc. Power Plant Equipment	25,410,407	151,515	31,744			25,530,178
15	(317) Asset Retirement Costs for Steam Production	25,434,117					25,434,117
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	1,295,516,537	(13,557,495)	697,207			1,281,261,835
17	B. Nuclear Production Plant						
18	(320) Land and Land Rights	1,879,588					1,879,588
19	(321) Structures and Improvements	473,005,941	8,034,321	1,822,587			479,217,675
20	(322) Reactor Plant Equipment	1,792,481,711	20,214,060	10,764,306			1,801,931,465
21	(323) Turbogenerator Units	720,340,088	9,432,805	3,805,746			725,967,147
22	(324) Accessory Electric Equipment	351,740,111	5,272,772	3,547,627			353,465,256
23	(325) Misc. Power Plant Equipment	293,736,055	28,792,703	3,683,527			318,845,231
24	(326) Asset Retirement Costs for Nuclear Production	496,814,452	(175,880,763)				320,933,689
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	4,129,997,946	(104,134,102)	23,623,793			4,002,240,051
26	C. Hydraulic Production Plant						
27	(330) Land and Land Rights	706,302	27,221				733,523
28	(331) Structures and Improvements	6,703,606	787,590	162,254			7,328,942
29	(332) Reservoirs, Dams, and Waterways	25,784,069	147,795	71,546			25,860,318
30	(333) Water Wheels, Turbines, and Generators	16,655,924	1,181,068	149,710			17,687,282
31	(334) Accessory Electric Equipment	6,740,016	1,184,313	154,125			7,770,204
32	(335) Misc. Power Plant Equipment	2,854,998	611,746	10,608			3,456,136
33	(336) Roads, Railroads, and Bridges	853					853
34	(337) Asset Retirement Costs for Hydraulic Production	318,520					318,520
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	59,764,288	3,939,733	548,243			63,155,778
36	D. Other Production Plant						
37	(340) Land and Land Rights	5,311,684					5,311,684
38	(341) Structures and Improvements	734,924	121,365				856,289
39	(342) Fuel Holders, Products, and Accessories						

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
40	(343) Prime Movers						
41	(344) Generators	63,645,801					63,645,801
42	(345) Accessory Electric Equipment	5,011,227	76,485				5,087,712
43	(346) Misc. Power Plant Equipment	841,237	140,965				982,202
44	(347) Asset Retirement Costs for Other Production						
44.1	(348) Energy Storage Equipment - Production						
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	75,544,873	338,815				75,883,688
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	5,560,823,644	(113,413,049)	24,869,243			5,422,541,352
47	3. Transmission Plant						
48	(350) Land and Land Rights	82,409,866	7,780,046	1,924			90,187,988
48.1	(351) Energy Storage Equipment - Transmission						
49	(352) Structures and Improvements	93,575,215	12,727,279	672,366			105,630,128
50	(353) Station Equipment	900,694,812	20,419,687	9,591,974			911,522,525
51	(354) Towers and Fixtures	230,520,953	124,709	586,067			230,059,595
52	(355) Poles and Fixtures	258,397,122	29,518,697	7,279,270			280,636,549
53	(356) Overhead Conductors and Devices	319,087,431	3,271,741	4,245,140			318,114,032
54	(357) Underground Conduit	11,964,902	15,925				11,980,827
55	(358) Underground Conductors and Devices	9,519,107	26,903	3,178			9,542,832
56	(359) Roads and Trails	91,159					91,159
57	(359.1) Asset Retirement Costs for Transmission Plant						
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	1,906,260,567	73,884,987	22,379,919			1,957,765,635
59	4. Distribution Plant						
60	(360) Land and Land Rights	34,081,794	5,366,029				39,447,823
61	(361) Structures and Improvements	70,699,359	10,484,837	170,986			81,013,210
62	(362) Station Equipment	592,075,608	41,744,286	10,470,280			623,349,614
63	(363) Energy Storage Equipment – Distribution	106,915					106,915
64	(364) Poles, Towers, and Fixtures	431,874,734	53,348,250	5,313,080			479,909,904
65	(365) Overhead Conductors and Devices	688,523,347	62,135,417	10,632,720			740,026,044
66	(366) Underground Conduit	202,411,863	30,806,819	70,996			233,147,686
67	(367) Underground Conductors and Devices	333,328,486	19,951,628	1,842,294			351,437,820
68	(368) Line Transformers	444,695,146	55,952,212	7,907,729			492,739,629
69	(369) Services	236,089,956	13,935,683	991,222			249,034,417
70	(370) Meters	161,407,333	37,207,721	14,752,441			183,862,613
71	(371) Installations on Customer Premises	32,847,135	2,099,327	926,626			34,019,836
72	(372) Leased Property on Customer Premises						
73	(373) Street Lighting and Signal Systems	25,759,409	1,556,090	247,586			27,067,913
74	(374) Asset Retirement Costs for Distribution Plant						
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	3,253,901,085	334,588,299	53,325,960			3,535,163,424
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT						
77	(380) Land and Land Rights						
78	(381) Structures and Improvements						
79	(382) Computer Hardware						
80	(383) Computer Software						
81	(384) Communication Equipment						
82	(385) Miscellaneous Regional Transmission and Market Operation Plant						
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper						
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)						
85	6. General Plant						
86	(389) Land and Land Rights	9,511,123					9,511,123
87	(390) Structures and Improvements	86,964,314	49,178,865	1,020,903			135,122,276
88	(391) Office Furniture and Equipment	6,768,638	1,730,581	828,307			7,670,912
89	(392) Transportation Equipment	71,084	128,080				199,164
90	(393) Stores Equipment	1,456,887	103,005				1,559,892
91	(394) Tools, Shop and Garage Equipment	21,709,489	3,016,025	1,569,059			23,156,455
92	(395) Laboratory Equipment	577,663					577,663

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
93	(396) Power Operated Equipment	543,715					543,715
94	(397) Communication Equipment	77,842,823	6,899,176	134,238			84,607,761
95	(398) Miscellaneous Equipment	14,021,990	1,004,365	2,584			15,023,771
96	SUBTOTAL (Enter Total of lines 86 thru 95)	219,467,726	62,060,097	3,555,091			277,972,732
97	(399) Other Tangible Property						
98	(399.1) Asset Retirement Costs for General Plant	1,308,356					1,308,356
99	TOTAL General Plant (Enter Total of lines 96, 97, and 98)	220,776,082	62,060,097	3,555,091			279,281,088
100	TOTAL (Accounts 101 and 106)	11,306,609,962	391,047,216	137,217,382			11,560,439,796
101	(102) Electric Plant Purchased (See Instr. 8)						
102	(Less) (102) Electric Plant Sold (See Instr. 8)						
103	(103) Experimental Plant Unclassified						
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	11,306,609,962	391,047,216	137,217,382			11,560,439,796

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (a)	* (Designation of Associated Company) (b)	Description of Property Leased (c)	Commission Authorization (d)	Expiration Date of Lease (e)	Balance at End of Year (f)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL					

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $250,000 or more. Group other items of property held for future use.
2. For property having an original cost of $250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Rockport Generating Plant Unit 1 (0111)	11/01/1984		1,034,109
3	Items under $250,000			280,262
21	Other Property:			
22	Items under $250,000			5,923
47	TOTAL			1,320,294

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107).
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts).
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	2024 Network Enhancements	1,882,850
2	224MW Lightsource bp Mayapple	3,768,238
3	24 I&M Incremental Fence T-CI	1,445,168
4	245MW EDF Renew Lake Trout	4,048,613
5	ADMS Imp DSN DNEX-IM D	12,828,905
6	Boundary 12kV Sta Opco	2,091,886
7	CIS-Common Deployment-IM D	6,693,305
8	CNH RELICENSE CONSTANTINE HYDR	1,081,134
9	Corp Prgrm Billing - I&M Trans	2,909,502
10	CRID Inverter Replacement U1	2,549,543
11	CRID Inverter Replacement U2	1,503,729
12	D/IM/Capital Blanket - IMPCo	1,555,677
13	Distributino CI	1,249,225
14	East Busco Battery Retirement	1,232,939
15	Ed-Ci-Impco-D Ast Imp	10,433,095
16	Ed-Ci-Impco-D Cust Serv	4,481,254
17	EDG Inverter lifecycle Replace	2,243,632
18	FW AMI VVO Circuits / Stations	5,977,638
19	German CVR Station Project	1,219,296
20	I&M	1,428,567
21	I&M - Distribution	4,506,445
22	I&M IN Major Eq/Spares- Distr	4,216,718
23	I&M 2023 DSN Dist	1,403,311
24	I&M CI	2,134,035
25	I&M D Supplemental Work	2,558,421
26	I&M Dist Supplemental Work	1,366,481
27	I&M Distibution CI	1,856,834
28	I&M Failure - Distribution CI	1,227,170
29	I&M Failure - Trans CI 1	1,072,428
30	I&M Failure - Trans CI 2	1,161,389
31	I&M Failure Distribution	1,343,690
32	I&M Grid Modernization CTS IN	2,114,277
33	I&M Grid Modernization DACR IN	2,036,885
34	I&M Major Eq/Spare -Distr CI	1,908,700
35	I&M OPCO CI	3,845,833
36	I&M T-OPCO	6,125,857
37	I&M Transmission Work	10,005,013
38	I&M-D Service Restoration Blkt	2,806,486
39	I&M-D Third Party Work Blkt	(2,393,314)
40	I&M-T-BlnktProj Under $3M	5,787,697
41	IDS/Cyber & Upgrade Network	7,644,810
42	IM T Work	1,767,590
43	IM Trans Work Baseline	4,379,193
44	IM/IN/D Reed Station Rebuild	3,837,989
45	IM/Stubey Rd 12kV CB addition	1,244,535
46	IMPCo Trans Pre Eng Parent 1	6,107,394
47	IMPCo Trans Pre Eng Parent 2	9,660,296

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
48	IMPCO-D Telecom	4,633,665
49	MI AMI VVO Circuits / Stations	1,645,426
50	Michigan Roadside Relocate	2,562,840
51	MUP Chemical Container Upgrade	4,818,491
52	Opco CI 1	3,547,486
53	Opco CI 2	7,530,503
54	Opco CI 3	2,161,941
55	Opco CI 4	(5,756,025)
56	Opco D CI 1	5,146,574
57	Opco D CI 2	1,505,792
58	Opco D CI 3	2,972,699
59	OPCO Supplemental CI	2,179,394
60	Opco T CI 1	9,342,816
61	Opco T CI 2	2,934,495
62	Price Skid Station	1,526,240
63	REP IN 1PH OH Rebuild	1,479,017
64	REP IN 3PH OH Rebuild	3,468,326
65	REP IN Circuit Ties	3,772,687
66	REP IN Cutouts, LAs	1,137,129
67	REP IN UG Cable Replacement	1,660,213
68	REP MI Circuit Ties	2,361,081
69	REP MI Rebuild 1ph OH Line	1,061,822
70	REP MI REBULD 3PH OH LINE	1,824,493
71	REP MI Replace UG Cable	1,087,722
72	RKP05CIIM Horiz RH ReplaceU1	3,000,488
73	RP-CI-IMPCo-G NMIB	12,771,987
74	Spare GSU Refurbishment	1,523,191
75	SPILLWAY CUT OFF WALL	12,001,115
76	SS-CI-IMPCo-D GEN PLT	4,410,152
77	Swanson Station Opco	1,440,591
78	T/IM/Capital Blanket - IMPCo	2,071,763
79	T/IM/Jefferson-Dumont Spacers	1,693,547
80	Trans OPCO	1,345,378
81	Transformer #5/#9 purchase spa	2,237,726
82	U1 Main Power Transformer Prch	6,374,445
83	U1 RCCA Replacement	1,217,191
84	WS-CI-IMPCo-G PPB	6,558,582
85	Other Minor Projects Under $1,000,000	55,177,131
43	Total	336,778,473

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 12, column (c), and that reported for electric plant in service, page 204, column (d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of Accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Line No.	Item (a)	Total (c + d + e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased To Others (e)
	Section A. Balances and Changes During Year				
1	Balance Beginning of Year	4,086,979,309	4,086,974,174	5,135	
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	419,823,656	419,823,549	107	
4	(403.1) Depreciation Expense for Asset Retirement Costs	2,517,737	2,517,737		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing				
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9.1	Other Accounts (Specify, details in footnote):	24,442,114	[a]24,442,114		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	446,783,507	446,783,400	107	
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(104,130,213)	(104,130,213)		
13	Cost of Removal	(65,946,865)	[b](65,946,865)		
14	Salvage (Credit)	9,117,356	[c]9,117,356		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(160,959,722)	(160,959,722)		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Other Debit or Cr. Items (Describe, details in footnote):	(4,476,964)	[d](4,476,964)		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	4,368,326,130	4,368,320,888	5,242	
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	844,001,000	844,001,000		
21	Nuclear Production	2,130,937,520	2,130,937,520		
22	Hydraulic Production-Conventional	41,156,296	41,156,296		
23	Hydraulic Production-Pumped Storage				
24	Other Production	19,821,931	19,821,931		
25	Transmission	490,422,263	490,417,021	5,242	
26	Distribution	795,232,113	795,232,113		
27	Regional Transmission and Market Operation				
28	General	46,755,007	46,755,007		
29	TOTAL (Enter Total of lines 20 thru 28)	4,368,326,130	4,368,320,888	5,242	

FOOTNOTE DATA

(a) Concept: OtherAccounts

Amortization of the Cook ARO	$ 23,942,046
Revised items due to IURC Final Order in I&M's Base Case Cause No. 44967	$ (442,916)
Amortize Indiana jurisdiction LCM deferred balances for carrying charges, depreciation, and property tax over a six year period as approved by the IURC in Cause No. 44182 LCM1 and amortize over recovery of all costs from Jul17-Jun18	
Over/under recovery of the payments to the Michigan Energy Optimization Program administrator and associated carrying charges	$ 95,676
Amortization per MPSC Order in I&M Base Case No. U-18370	$ (167,049)
Record over/under recovery of the I&M South Bend Solar Project	$ 90,067
ARO depr exp 1080013	$ 924,290
Total	$ 24,442,114

(b) Concept: CostOfRemovalOfPlant

Includes $13,388,540 of removal cost in retirement work in progress (RWIP).

(c) Concept: SalvageValueOfRetiredPlant

Includes $(2,367,412) of salvage in retirement work in progress (RWIP).

(d) Concept: OtherAdjustmentsToAccumulatedDepreciation

To amortize the deferred incremental depreciation expense for the MI portion of Rockport Unit 2 through December 2028 as a result of the pending purchase of Rockport Unit 2, aligning both the GAAP and regulatory depreciable lives through Dec. 2028.	$ (3,207,395)
Defer ARO Deprec & Accretion Exp	$ (1,363,675)
Jay County Rural Electric Membership Corporation Acquisition	$ 21,400
Wabash valley Power Association Acquisition	$ 72,706
TOTAL	$ 4,476,964

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Account 123.1, Investments in Subsidiary Companies.
2. Provide a subheading for each company and list thereunder the information called for below. Sub-TOTAL by company and give a TOTAL in columns (e), (f), (g) and (h). (a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity, and interest rate. (b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.
4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues from investments, including such revenues from securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if different from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)	Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
17								
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36								
37								
38								
39								
40								
41								

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)	Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)
42	Total Cost of Account 123.1 $		Total					
					Page 224-225			

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	84,069,956	79,612,046	Electric
2	Fuel Stock Expenses Undistributed (Account 152)	3,988,855	3,749,464	Electric
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	101,425,986	122,007,495	Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	103,334,146	87,307,405	Electric
8	Transmission Plant (Estimated)	286,359	288,652	Electric
9	Distribution Plant (Estimated)	781,581	874,118	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	(a)584,519	(a)427,067	Electric
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	206,412,591	210,904,737	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)	1,559,255	1,301,835	River Transport
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)			
17				
18				
19				
20	TOTAL Materials and Supplies	296,030,657	295,568,082	

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: PlantMaterialsAndOperatingSuppliesOther

Assigned to - Other includes customer account, administrative and general expenses.

(b) Concept: PlantMaterialsAndOperatingSuppliesOther

Assigned to - Other includes Customer Account, Administrative and General Expenses.

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on Line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.
6. Report on Line 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquired and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of and identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year		Year One		Year Two		Year Three		Future Years		Totals	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
1	Balance-Beginning of Year	603,770	7,537,479	80,899		80,899		80,899		2,120,431		2,966,898	7,537,479
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)			10,000						91,296		101,296	
5	Returned by EPA												
6													
7													
8	Purchases/Transfers:												
9	Restricted Title IV SO2 Allowances												
10	Other (a)		(7,484,483)										(7,484,483)
11													
12													
13													
14													
15	Total												
16													
17	Relinquished During Year:												
18	Charges to Account 509	6,480	52,996									6,480	52,996
19	Other:												
20	Allowances Used												
20.1	Allowances Used												
21	Cost of Sales/Transfers:												
22	Consent Decree Surrenders			73,568								73,568	
23													
24													
25													
26													
27													
28	Total			73,568								73,568	
29	Balance-End of Year	597,290		17,331		80,899		80,899		2,211,727		2,988,146	
30													
31	Sales:												
32	Net Sales Proceeds(Assoc. Co.)												
33	Net Sales Proceeds (Other)												
34	Gains		53										53
35	Losses												
	Allowances Withheld (Acct 158.2)												
36	Balance-Beginning of Year	357		357		357		357		56,556		57,984	
37	Add: Withheld by EPA									714		714	
38	Deduct: Returned by EPA												

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year		Year One		Year Two		Year Three		Future Years		Totals	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
39	Cost of Sales	357								357		714	
40	Balance-End of Year			357		357		357		56,913		57,984	
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)												
45	Gains												
46	Losses												

Page 228(ab)-229(ab)a

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: AllowancesInventoryPurchasesTransfersDescription
As approved in the Michigan base case U-21461, reclass excess MI and FERC SO2 allowances from allowance inventory #1581 to a Regulatory Asset #1823 of $7,484,483 to be amortized over 5 years from July 2024 through July 2029.

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on Line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.
6. Report on Line 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquired and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of and identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year		Year One		Year Two		Year Three		Future Years		Totals	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
1	Balance-Beginning of Year	121,696	2,408									121,696	2,408
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)	2,112		27,017								29,129	
5	Returned by EPA												
6													
7													
8	Purchases/Transfers:												
9													
10													
11													
12													
13													
14													
15	Total												
16													
17	Relinquished During Year:												
18	Charges to Account 509	2,815										2,815	
19	Other:												
20	Allowances Used												
20.1	Allowances Used												
21	Cost of Sales/Transfers:												
22	Wolverine Power Supply Cooperative, Inc.												
23	Surrenders												
24	Consent Decree Surrenders												
25	Unknown												
26	Other												
27													
28	Total												
29	Balance-End of Year	120,993	2,408	27,017								148,010	2,408
30													
31	Sales:												
32	Net Sales Proceeds(Assoc. Co.)												
33	Net Sales Proceeds (Other)												
34	Gains												
35	Losses												
	Allowances Withheld (Acct 158.2)												
36	Balance-Beginning of Year												
37	Add: Withheld by EPA												
38	Deduct: Returned by EPA												
39	Cost of Sales												

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year		Year One		Year Two		Year Three		Future Years		Totals	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
40	Balance-End of Year												
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)												
45	Gains												
46	Losses												
Page 228(ab)-229(ab)b													

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognized During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
20	TOTAL					

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of COmmission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognized During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL					

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	AD1-100	(65)	186		
3	AE1-070	3,063	186	4,655	186
4	AF1-071	835	186	835	186
5	AF1-084	4,621	186	4,252	186
6	AF1-088	21,817	186	17,556	186
7	AF1-091	2,202	186	2,202	186
8	AF1-092	3,040	186	4,797	186
9	AF1-141	3,605	186	3,833	186
10	AF1-148	1,670	186	1,670	186
11	AF1-161	5,229	186	5,487	186
12	AF1-176	4,759	186	4,458	186
13	AF1-202	2,405	186	1,772	186
14	AF1-204	5,485	186	4,536	186
15	AF1-207	2,202	186	2,043	186
16	AF1-215	587	186		
17	AF1-223	825	186	825	186
18	AF1-268	4,272	186	3,778	186
19	AF1-322	2,663	186	2,871	186
20	AF2-008	22,529	186	18,328	186
21	AF2-094	2,030	186	2,030	186
22	AF2-125	1,624	186		
23	AF2-132	1,825	186	1,715	186
24	AF2-133	1,770	186	1,770	186
25	AF2-162	680	186	680	186
26	AF2-173	3,620	186	4,069	186
27	AF2-204	1,627	186	1,932	186
28	AF2-205	2,464	186	2,464	186
29	AF2-224	1,221	186	1,221	186
30	AF2-370			1,003	186
31	AF2-389	18,703	186	18,682	186
32	AF2-396	10,305	186	10,100	186
33	AG1-017	1,868	186	1,868	186
34	AG1-047	2,401	186	2,180	186
35	AG1-109	1,020	186	1,020	186
36	AG1-222	1,152	186	2,792	186
37	AG1-224	295	186		
38	AG1-232	1,885	186	1,735	186
39	AG1-237	2,456	186	2,247	186
40	AG1-302	2,268	186	2,753	186
41	AG1-324	3,439	186	2,963	186
42	AG1-349	3,251	186	3,149	186
43	AG1-365	255	186	255	186
44	AG1-366	880	186	880	186
45	AG1-367	677	186	685	186

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
46	AG1-368	1,921	186	1,810	186
47	AG1-375	853	186		
48	AG1-417	17,469	186	17,469	186
49	AG1-424			822	186
50	AG1-433	365	186	365	186
51	AG1-436	1,446	186	929	186
52	AG1-447	181	186		
53	AG1-453	996	186	1,132	186
54	AG1-454	4,736	186	4,873	186
55	AG1-555	1,037	186	569	186
56	AG2-242	(1,249)	186		
57	AI2-144	(230)	186		
58	J1180 MISO	10,364	186		
59	J793	(1,105)	186		
60	PJM - #AE2-089	426	186	84	186
61	PJM - #AE2-130	981	186	981	186
62	PJM - #AE2-220	1,888	186	1,888	186
63	PJM - #AE2-234	18,759	186	18,846	186
64	PJM - #AE2-276	3,045	186		
65	PJM - #AF1-118	1,471	186	846	186
66	PJM - #AF1-119	2,098	186	1,940	186
67	PJM - #AF1-221	36,211	186	39,289	186
20	Total				
21	**Generation Studies**				
39	Total				
40	Grand Total				

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	PJM Annual Transmission Requirement	1,069,018	1,084,421	456	1,069,018	1,084,421
2	City of Fort Wayne Settlement, IURC Cause Order #44075, Amortization Period: 03/2013 - 04/2025	1,236,511		588	914,590	321,921
3	Cook Life Cycle Management Program - Michigan Portion, MPSC Case U-18370, Amortization Period: 04/2018 - 10/2034	11,060,122	459,678	403, 182, 421, 408	1,472,991	10,046,809
4	Cook Plant Refueling Outage Deferral	55,658,917	64,296,169	519, 520, 523, 524, 528, 529, 530, 531, 532	76,943,766	43,011,320
5	Cook Plant Water Study Cost, IURC Cause Order #45235 MPSC Case No. U-20359, Amortization Period: 02/2020 - 03/2035	7,963,306		524	713,793	7,249,513
6	Cook Turbine Replacement CC - Indiana, IURC Cause Order #44075, Amortization Period 7/2018 - 01/2038	8,437,998	314,629	182, 421	915,919	7,836,708
7	Cook Unit 2 Baffle Bolts, IURC Cause Order #44075, Amortization Period: 03/2013 - 02/2038	4,249,097	(1)	530	299,936	3,949,160
8	Cook Uprate Project, IURC Cause Order #44967MPSC Case No. U-18370, Amortization Period: 4/2018 - 6/2033	22,903,646		524	2,417,536	20,486,110
9	COVID-19 Deferred Bad Debt Expense, IURC Cause Order #45576MPSC Case No. U-21461, Amortization Period: 2/2022 - 2/2024	250,943		426	250,943	
10	Deferred Depreciation Rockport Unit 2, Amortization Period: 12/2021 - 12/2028	16,036,973		108	3,207,395	12,829,578
11	Deferred Storm Expense	33,069,467	4,765,119	593	11,279,541	26,555,045
12	DSM Energy Optimization Program - Michigan	5,271,696	1,229,426	908, 421	4,217,583	2,283,539
13	IN PJM Exp and OSS Margin		2,528,772	254		2,528,772
14	IN Tax Rider Under Recovery	784,349		0		784,349
15	Indiana Environmental Compliance Rider	8,134,587	455,916	502	7,215,053	1,375,450
16	Indiana Plugged In Rebate Deferral	126,927	88,818	182, 431	79,778	135,967
17	Indiana Resource Adequecy Rider Under Recovery	182,114	4,880,520	555	437,721	4,624,913
18	MI Low Income Cost Recov Surch, MPSC Case U-21461, Amortization Period: 7/2024 - 7/2026		1,025,293	182	481,478	543,815
19	Michigan Dry Cask Storage Deferral	381	288	182, 431	507	162
20	Michigan Home Energy Management and Work Energy Management Programs	803,826	333,714	908	64	1,137,476
21	Michigan Plugged In Rebate Deferral	80,739	45,278	182, 431	31,977	94,040
22	Michigan Under Recovered Fuel Interest	695,795	1,601,564	431	1,511,416	785,943
23	NOLC Regulatory Asset		32,018,900	407.00	5,288,355	26,730,545
24	Nuclear Decommissioning Study Expense	49,625	172,383	923	49,921	172,087
25	Rate Case Expenses	1,663,905	1,215,576	928	1,645,517	1,233,964
26	River Transportation Selling Price Variance	5,964,878	14,940,907	417	15,263,581	5,642,204
27	Rockport DSI Project - Indiana 20% Non Federal Mandate Rider, IURC Cause Order #44967, Amortization Period: 7/2018 - 12/2027	5,061,751	152,604	403, 500, 502, 421	1,436,756	3,777,599
28	SFAS 106 Medicare Subsidy, Amortization Period: 01/2013 - 12/2024	1,020,135		926	1,020,135	
29	SFAS 109 Deferred FIT	167,621,179	154,259,064	190, 236, 254, 255	148,875,858	173,004,385
30	SFAS 109 Deferred SIT	236,104,582	17,491,575	182, 283	19,127,759	234,468,398
31	SFAS 112 Post Employment Benefits	7,028,415	1,615,394	228, 926	1,336,838	7,306,971
32	SFAS 158 Employer Accounting	25,323,992	105,325,915	129, 190, 219, 228	116,063,637	14,586,270
33	Spent Nuclear Fuel Incremental Costs	2,143		520	2,143	
34	Unrealized Loss on Forward Commitments Regulated Assets/Liabilities	3,105,742	158,265	175, 244, 254	3,171,817	92,190
35	Unrecovered Fuel Costs - Indiana		203,352	440, 442, 444	203,352	

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
36	Unrecovered Fuel Costs - Michigan	14,130,073	17,768,939	440, 442, 444	22,037,502	9,861,510
37	PJM Transmission True Up	4,574,283	7,086,056	447	6,398,935	5,261,404
38	Deferred Renewable Development Costs	210,920	6,119,317	183, 407, 426, 182, 431	1,048,632	5,281,605
39	Excess SO2 Allowance Inventory	14,836,845	7,484,483	509	3,659,482	18,661,846
40	Deferred Integrated Resource Plan Expense		92,118			92,118
41	ARO Retired Plants from Legacy CCR Rules, EPA-HQ-OLEM-2020-0107		74,022,419			74,022,419
44	TOTAL	664,714,880	523,236,871		460,091,225	727,860,526

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS		Balance at End of Year (f)
				Credits Account Charged (d)	Credits Amount (e)	
1	Property Taxes	51,932,127	72,338,195	107/236/408	74,573,076	49,697,246
2	Property Taxes - Capital Leases	81,143	83,822	408	81,143	83,822
3	Agency Fees, Factored Accts Rec	3,128,194	43,273,781	142/173/184/ 426	43,191,052	3,210,923
4	River Transport Division	4,411,012	67,336,187	101/121/134/143/163/182/186/242/408/417/426	66,615,801	5,131,398
5	Deferred Expenses		27,898			27,898
6	Unamortized Credit Line Fees	612,688	721,655	431	300,582	1,033,761
7	Defd Non-taxable Leased Assets	504,553	694,514	142/143/186/184	866,812	332,255
8	Transource OU Acctg for Def Asset	52,237	115,936	565	77,008	91,165
9	Long Term Assoc	34,829,359	43,780,063	186/456/449/565	52,226,857	26,382,565
10	Unidentified Cash Receipts	97,915	3,787	131/146/253/593	101,595	107
11	Minor Items	3,569	9,992,437	151/242/562/566	9,996,011	(5)
47	Miscellaneous Work in Progress	3,693,963				3,361,537
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	99,346,760				89,352,672

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance at Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2	PT Repairs UOP - NORM	17,910,229	18,742,699
3	EXCESS ADFIT - PROTECTED.	93,509,727	66,778,416
4	REG LIABILITY-SFAS 143 - ARO	342,507,010	425,891,523
5	ACCRD BOOK ARO EXPENSE - SFAS 143	418,887,358	417,213,322
6	TC-ACC INT PRE 4 7 83 DISP CST	(16,774,647)	(17,068,699)
7	Other	(1,686,523)	30,573,122
8	TOTAL Electric (Enter Total of lines 2 thru 7)	854,353,154	942,130,383
9	Gas		
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)		
17.1	Other (Specify)	159,661,115	[a]130,096,671
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	1,014,014,269	1,072,227,054

Notes

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxes

Line 17 Other - Detail	Balance at Beginning of Year	Balance at End of Year
SFAS 133	1,415,127	1,298,994
Non Utility Items - 190.2	3,493,009	3,324,772
SFAS 109-Regulatory Assets - 190.3 & 190.4	156,011,667	126,858,968
Other Comprehensive Income	(1,258,688)	(1,386,063)
Accu Def Income Taxes Pension-OCI	—	—
Total	$ 159,661,115	$ 130,096,671

Line 18 Reconciliation of details applicable to Account 190, Line 18, Columns (b) and (c) :		
Balance at Beginning of Year	$	1,014,014,269
(Less) Amounts Debited to:		
(a) Account 410.1		(130,044,370)
(b) Account 410.2		(3,014,683)
(c) 1823/254/219/129/427		(47,409,516)
(Plus) Amounts Credited to:		
(a) Account 411.1		197,853,257
(b) Account 411.2		63,812,272
(c) 1823/254/219/129/427		(22,984,175)
Balance at End of Year	$	1,072,227,054

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.
3. Give details concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or noncumulative.
5. State in a footnote if any capital stock that has been nominally issued is nominally outstanding at end of year.
6. Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purpose of pledge.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of Shares Authorized by Charter (b)	Par or Stated Value per Share (c)	Call Price at End of Year (d)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Shares (e)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Amount (f)	Held by Respondent As Reacquired Stock (Acct 217) Shares (g)	Held by Respondent As Reacquired Stock (Acct 217) Cost (h)	Held by Respondent In Sinking and Other Funds Shares (i)	Held by Respondent In Sinking and Other Funds Amount (j)
1	Common Stock (Account 201)									
2		2,500,000			1,400,000	56,583,866				
5	Total	2,500,000			1,400,000	56,583,866				
6	Preferred Stock (Account 204)									
7										
8										
9										
10	Total									

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 2025-04-08	Year/Period of Report End of: 2024/ Q4

Other Paid-in Capital

1. Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as a total of all accounts for reconciliation with the balance sheet, page 112. Explain changes made in any account during the year and give the accounting entries effecting such change.

a. Donations Received from Stockholders (Account 208) - State amount and briefly explain the origin and purpose of each donation.
b. Reduction in Par or Stated Value of Capital Stock (Account 209) - State amount and briefly explain the capital changes that gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
c. Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210) - Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
d. Miscellaneous Paid-In Capital (Account 211) - Classify amounts included in this account according to captions that, together with brief explanations, disclose the general nature of the transactions that gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	**Donations Received from Stockholders (Account 208)**	
2	Beginning Balance Amount	972,666,991
3.1	Increases (Decreases) from Sales of Donations Received from Stockholders	
4	Ending Balance Amount	972,666,991
5	**Reduction in Par or Stated Value of Capital Stock (Account 209)**	
6	Beginning Balance Amount	
7.1	Increases (Decreases) Due to Reductions in Par or Stated Value of Capital Stock	
8	Ending Balance Amount	
9	**Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210)**	
10	Beginning Balance Amount	120,554
11.1	Increases (Decreases) from Gain or Resale or Cancellation of Reacquired Capital Stock	
12	Ending Balance Amount	120,554
13	**Miscellaneous Paid-In Capital (Account 211)**	
14	Beginning Balance Amount	20,623,324
15.1	Increases (Decreases) Due to Miscellaneous Paid-In Capital	14,025,530
16	Ending Balance Amount	34,648,854
17	**Other Paid in Capital**	
18	Beginning Balance Amount	
19.1	Increases (Decreases) in Other Paid-In Capital	
20	Ending Balance Amount	
40	Total	1,007,436,399

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1		
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22	TOTAL	

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by Balance Sheet Account the details concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other Long-Term Debt.
2. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds, and in column (b) include the related account number.
3. For Advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received, and in column (b) include the related account number.
4. For receivers' certificates, show in column (a) the name of the court and date of court order under which such certificates were issued, and in column (b) include the related account number.
5. In a supplemental statement, give explanatory details for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a)principal advanced during year (b) interest added to principal amount, and (c) principal repaid during year. Give Commission authorization numbers and dates.
6. If the respondent has pledged any of its long-term debt securities, give particulars (details) in a footnote, including name of the pledgee and purpose of the pledge.
7. If the respondent has any long-term securities that have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
8. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (m). Explain in a footnote any difference between the total of column (m) and the total Account 427, Interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
9. Give details concerning any long-term debt authorized by a regulatory commission but not yet issued.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Related Account Number (b)	Principal Amount of Debt Issued (c)	Total Expense, Premium or Discount (d)	Total Expense (e)	Total Premium (f)	Total Discount (g)	Nominal Date of Issue (h)	Date of Maturity (i)	AMORTIZATION PERIOD Date From (j)	AMORTIZATION PERIOD Date To (k)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (l)	Interest for Year Amount (m)
1	Bonds (Account 221)												
2	None												
3	Subtotal												
4	Reacquired Bonds (Account 222)												
5													
6													
7													
8	Subtotal												
9	Advances from Associated Companies (Account 223)												
10	None												
11	Subtotal												
12	Other Long Term Debt (Account 224)												
13	[a] Spent Nuclear Fuel Disposal Costs Prior To April 7, 1983 - Basic Fee Assessment & Interest		316,289,892									316,289,892	
14	Series 2002 A - 2.75% Fixed Rate		50,000,000		296,785			08/01/1985	06/01/2025	08/01/1985	06/01/2025	50,000,000	1,375,000
15							325,000						
16							136,351						
17					444,593			06/01/2007	06/01/2025	06/01/2007	06/01/2025		
18					386,217			12/01/2017	06/01/2025	12/01/2017	06/01/2025		
19					74,250					06/01/2020	05/31/2021		
20					74,250					06/01/2021	05/31/2022		
21					74,250					06/01/2022	05/31/2023		
22	[b] Series 2009 A - 3.05% Fixed Rate		50,000,000		353,976			03/26/2009	06/01/2025	04/01/2009	05/31/2014	50,000,000	1,525,000
23					249,468					06/01/2014	05/31/2018		
24					354,263			06/01/2018	06/01/2025	06/01/2018	06/01/2025		
25	[c] Series 2009 B - 3.05% Fixed Rate		50,000,000		353,976			03/26/2009	06/01/2025	04/01/2009	05/31/2014	50,000,000	1,525,000

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Related Account Number (b)	Principal Amount of Debt Issued (c)	Total Expense, Premium or Discount (d)	Total Expense (e)	Total Premium (f)	Total Discount (g)	Nominal Date of Issue (h)	Date of Maturity (i)	AMORTIZATION PERIOD Date From (j)	AMORTIZATION PERIOD Date To (k)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (l)	Interest for Year Amount (m)
26					249,469					06/01/2014	05/30/2018		
27					354,262			06/01/2018	06/01/2025	06/01/2018	06/01/2025		
28	[d] Series D -0.750% Fixed Rate		40,000,000		632,137			06/01/2021	04/01/2025	06/01/2021	04/01/2025	40,000,000	300,000
29					40,998					06/01/2021	04/01/2025		
30	Series L - 3.75% Fixed Rate		300,000,000		3,139,683		2,088,000	06/29/2017	07/01/2047	06/29/2017	07/01/2047	300,000,000	11,250,000
31	Series K - 4.55% Fixed Rate		400,000,000		4,036,755		1,372,000	03/03/2016	03/15/2046	03/03/2016	03/15/2046	400,000,000	18,200,000
32	Series H - 6.05% Fixed Rate		400,000,000		3,815,383		2,272,000	11/14/2006	03/15/2037	11/14/2006	03/15/2037	400,000,000	24,200,000
33	Amortization of Cash Flow Hedges on 6.05% SUN									11/14/2006	02/28/2037		382,729
34	Series O- 3.250% Fixed Rate		450,000,000		4,825,845		3,501,000	04/29/2021	05/01/2051	04/29/2021	05/01/2051	450,000,000	14,625,000
35	[e] Fort Wayne Settlement		26,802,388					03/01/2010	02/28/2025	03/01/2010	02/28/2025	215,583	
36	Series P - 5.63% Fixed Rate		500,000,000		5,215,340		155,000	03/21/2023	04/01/2053	03/21/2023	04/01/2053	500,000,000	28,125,000
37	Amortization of settle hedge at debt issuance on 5.63% SUN									03/21/2023	02/28/2033		131,275
38	Series M - 3.85% Fixed Rate		350,000,000		2,865,394		1,102,500	05/02/2018	05/15/2028	05/02/2018	05/15/2028	350,000,000	13,475,000
39	Series N - 4.25% Fixed Rate Per IURC Authority Cause #45057		475,000,000		4,926,878		2,717,000	08/08/2018	08/15/2048	08/08/2018	08/15/2048	475,000,000	20,187,500
28	Subtotal		3,408,092,280		32,764,172		13,668,851					3,381,505,475	135,301,504
33	TOTAL		3,408,092,280									3,381,505,475	135,301,504

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: ClassAndSeriesOfObligationCouponRateDescription

The Federal government is responsible for permanent spent nuclear fuel disposal and assess fees to nuclear plant owners for spent nuclear fuel disposal. I&M has not paid the government the pre-April 1983 fees due to continued delays and uncertainties related to the federal disposal program and has recorded this future payment as long term debt...

(b) Concept: ClassAndSeriesOfObligationCouponRateDescription

The $50 million 6.25% City of Rockport Series 2009B PCRB was issued 3/26/2009 with a maturity date of 6/1/2025 and a mandatory tender date of 6/2/2014. On the 6/2/2014 put date, the PCRB was converted to 1.75% with a mandatory tender date of 6/1/2018. On the 6/1/2018 put date, the PCRB was converted to 3.05% with a maturity date of 6/1/2025. Issuance expenses totaling $354,262 will be amortized through 6/1/2025.

(c) Concept: ClassAndSeriesOfObligationCouponRateDescription

The $50 million 6.25% City of Rockport Series 2009A PCRB was issued 3/26/2009 with a maturity date of 6/1/2025 and a mandatory tender date of 6/2/2014. On the 6/2/2014 put date, the PCRB was converted to 1.75% with a mandatory tender date of 6/1/2018. On the 6/1/2018 put date, the PCRB was converted to 3.05% with a maturity date of 6/1/2025. Issuance expenses totaling $354,263 will be amortized through 6/1/2025.

(d) Concept: ClassAndSeriesOfObligationCouponRateDescription

The $40 million City of Rockport Series D,PCRB was issued on June , 2021. The interest rate is variable with the maturity date of April 1, 2025..The $40M million was reissued on December 14 ,2021 and the interest rate converted to 0.75% with the maturity date of April 1,2025

(e) Concept: ClassAndSeriesOfObligationCouponRateDescription

On August 10, 2011, the Indiana Utility Regulatory Commission issued a Final Order in Cause No. 43980 approving an agreement between Indiana Michigan Power Company and the City of Fort Wayne, Indiana to settle all disputes and other matters between them relating to the 1974 Lease Agreement pursuant to which I&M leased certain electric property from the city. The agreement required I&M to purchase the leased property and settle certain claims asserted by the City of Fort Wayne. Pursuant to the agreement, I&M paid the city $5 million within thirty days of the effective date of the final order. Further, the agreement provided that I&M pay the city a total of $34.2 million, including interest, over 15 years (March 2010 to February 2025), and that the City of Fort Wayne recognize I&M as the exclusive electricity provider in the Fort Wayne area. Interest on this liability is recorded in account 431.

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	391,365,619
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5		
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15		
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20		
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	[a]273,030,720
28	Show Computation of Tax:	
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: FederalTaxNetIncome

FOOTNOTE DATA

Schedule Page: 261 Line No.: 28 Column: b A

Description	Amount('000)
Net Income for the Year per Page 117	$391,366
Federal Income Taxes	$(102,213)
State Income Taxes	$7,000
Pre-Tax Book Income	$296,153
Increase (Decrease) in Taxable Income resulting from:	
Excess tax vs book depreciation	$113,392
Asset Retirement Obligation	$17,725
Afudc / interest capitalized	$(11,266)
Percent repair allowance	$(144,314)
Removal costs	$(61,480)
Accelerated amortization	$14,223
Revenue refunds	$48,717
Deferred Fuel Costs	$4,269
Equity in earnings of subsidiaries	$—
Book accruals	$21,288
Book deferrals	$(3,901)
Other miscellaneous	$(21,292)
OPEB - Others miscellaneous	$(21,859)
Permanent Schedule M's	$1,273
Tax accruals	$(93)
Tax deferrals	$—
Nuclear fuel adjustments	$—
Nuclear fuel disposal costs	$11
Book deferred nuclear costs	$12,648
Emission Allowances	$7,537
Taxable Income before State Taxes	$273,031
State & Local Current Tax	$9,782
Federal Taxable Income	$263,249
Computation of Tax:	
FIT on Current Year Taxable Income	$55,282
Tax Credits	$(36,874)
Solar Investment Tax Credits	$—
NOL Reclass	$—
R&D Credit	$—
Estimated Tax Currently Payable (b)	$18,408
Adjustments of Prior Year's Accruals	$(1,787)
Tax Expense for R/C of Net Operating Loss (Prior Yr)	
Estimated Current Federal Income Taxes	$16,621

Represents the allocation of estimated current year net operating tax income of American Electric Power Company, Inc.

FOOTNOTE DATA

Instruction 2.
* The tax computation above represents an estimate of the Company's allocated portion of the System consolidated Federal Income Tax.
The computation of actual 2023 System Federal income taxes will not be available until the consolidated Federal Income tax return is filed by October 2024.The actual allocation of the System consolidated Federal income tax to the members of the consolidated group will not be available until after the Consolidated Federal Income Tax Return is filed."

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

TAXES ACCRUED, PREPAID AND CHARGES DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are known, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (g) and (h). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (g) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.
5. If any tax (exclude Federal and State income taxes) covers more than one year, show the required information separately for each tax year, identifying the year in column (d).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (i) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (l) through (o) how the taxes were distributed. Report in column (o) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 409.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (o) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	State (c)	Tax Year (d)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARG		
					Taxes Accrued (Account 236) (e)	Prepaid Taxes (Include in Account 165) (f)				Taxes Accrued (Account 236) (j)	Prepaid Taxes (Included in Account 165) (k)	Electric (Account 408.1, 409.1) (l)	Extraordinary Items (Account 409.3) (m)	Adjustment to Ret. Earnings (Account 439) (n)
1	Pers Prop Leased	Property Tax	IN		1,086,900	0	330,851	452,251		965,500	0	330,851		
2	Pers Prop Leased	Property Tax	MI		98,330	0	115,628	86,565		127,393	0	112,949		
3	Real & Pers Prop	Property Tax	AR		0	0	3,446	3,446		0	0	0		
4	Real & Pers Prop	Property Tax	IL		0	0	1,093	1,093		0	0	1,093		
5	Real & Pers Prop	Property Tax	IN		22,440,673	0	23,033,199	23,277,837		22,196,035	0	20,818,159		
6	Real & Pers Prop	Property Tax	KY		1,131,000	0	258,000	257,778		1,131,222	0	0		
7	Real & Pers Prop	Property Tax	LA		0	0	2,097	2,097		0	0	0		
8	Real & Pers Prop	Property Tax	MI		65,833,021	0	49,018,293	54,069,236		60,782,077	0	50,301,750		
9	Real & Pers Prop	Property Tax	MO		0	0	22,195	22,195		0	0	0		
10	Real & Pers Prop	Property Tax	TN		0	0	1,242	1,242		0	0	0		
11	Real & Pers Prop	Property Tax	VA		0	0	192	192		0	0	0		
12	Real & Pers Prop	Property Tax	WV		227,974	0	181,031	169,615		239,390	0	2,019		
13	Real & Pers Prop	Property Tax	WY		0	0	9,204	1,646		7,558	0	0		
14	Real Prop Leased	Property Tax	IN		0	0	237,138	237,138		0	0	0		
15	Real Prop Leased	Property Tax	MI		0	0	306,142	208,544		97,598	0	306,142		
16	Unemployment Tax	Unemployment Tax	IN		40,152	0	236,712	220,934		55,930	0	133,379		
17	Unemployment Tax	Unemployment Tax	MI		60,638	0	244,028	228,213		76,453	0	172,007		
18	Unemployment Tax	Unemployment Tax	OH		198	0	7,350	3,538		4,010	0	7,748		
19	Unemployment Tax	Unemployment Tax	WV		(85)	0	15,537	15,661		(208)	0	(5,044)		
20	Unemployment Tax	Unemployment Tax	(blank)		25,366	0	107,907	97,515		35,759	0	69,991		
21	Sales Tax	Sales And Use Tax	MI		0	678,717	0	109,697		0	788,415	0		
22	Use Tax	Sales And Use Tax	IN		514,245	0	7,103,279	7,230,388		387,136	0	0		
23	Use Tax	Sales And Use Tax	MI		48,510	46,331	1,341,371	1,339,416		93,335	89,201	3,584		

Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	State (c)	Tax Year (d)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARG		
					Taxes Accrued (Account 236) (e)	Prepaid Taxes (Include in Account 165) (f)				Taxes Accrued (Account 236) (j)	Prepaid Taxes (Included in Account 165) (k)	Electric (Account 408.1, 409.1) (l)	Extraordinary Items (Account 409.3) (m)	Adjustment to Ret. Earnings (Account 439) (n)
24	Use Tax	Sales And Use Tax	WV		2,361	0	32,783	32,301		2,843	0	0		
25	City Tax	Income Tax			(30,028)	0	0	0		(30,028)	0	0		
26	City Tax	Income Tax	MI		(1,261)	0	0	0		(1,261)	0	0		
27	City Tax	Income Tax	MULTI		0	0	0	0		0	0	0		
28	City Tax	Income Tax	OH		(3,454)	0	0	900		(4,354)	0	0		
29	Federal Income	Income Tax			3,784,888	0	2,595,924	(90,446)		6,471,257	0	25,567,128		
30	State Income Tax	Income Tax	IL		258,943	0	(28,820)	0		230,123	0	(16,820)		
31	State Income Tax	Income Tax	IN		(3,390,888)	0	5,500,865	7,472,900		(5,362,923)	0	7,211,648		
32	State Income Tax	Income Tax	KY		170,435	0	64,471	0		234,906	0	83,170		
33	State Income Tax	Income Tax	MI		3,554,400	0	1,298,492	0		4,852,891	0	1,700,481		
34	State Income Tax	Income Tax	MO		10,098	0	0	1,800		8,298	0	0		
35	State Income Tax	Income Tax	MULTI		6,386,332	0	0	0		6,386,332	0	0		
36	State Income Tax	Income Tax	OH		245	0	0	0		245	0	0		
37	State Income Tax	Income Tax	UT		0	0	0	0		0	0	0		
38	State Income Tax	Income Tax	WV		492,409	0	201,801	0		694,210	0	243,426		
39	State Income Tax FIN48	Income Tax	FIN48		0	0	0	0		0	0	0		
40	Excise Tax	Fuel Tax			363,113	0	692,232	553,863		501,482	0	59,022		
41	Special Fuel Tax	Fuel Tax	WV		31,408	0	157,125	147,925		40,608	0	0		
42	Federal Insurance Tax	Federal Insurance Tax	(blank)		1,542,900	0	19,690,379	19,373,674		1,859,605	0	12,509,063		
43	State Franchise	Franchise Tax	KY		43,873	0	0	0		43,873	0	0		
44	State Franchise	Franchise Tax	OK		0	0	0	0		0	0	100		
45	State Franchise	Franchise Tax	WV		7,900	0	0	0		7,900	0	0		
46	Ohio CAT Tax	Other State Tax	OH		2,400	0	5,172	72		7,500	0	5,172		
47	Fuel Tax	Other Taxes and Fees	IN		0	0	0	0		0	0	0		
48	Fuel Tax	Other Taxes and Fees	MI		0	0	0	0		0	0	0		
40	TOTAL				104,732,995	725,048	112,786,359	115,529,226		102,142,694	877,615	119,617,019		

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g). Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)	Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION (j)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)				
1	Electric Utility									
2	3%				411.4					
3	4%				411.4					
4	7%	126,300			411.4	81,592		44,708		
5	10%	1,950,243	411.1		411.4	1,103,680		846,563	43 Years	
6	State DITC		411.1		411.4					
7	30%	13,696,181			411.4	749,967		12,946,214		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	15,772,724				1,935,239		13,837,485		
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)									
10										`
47	OTHER TOTAL									
48	GRAND TOTAL	15,772,724						13,837,485		

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

OTHER DEFERRED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS		Credits (e)	Balance at End of Year (f)
			Contra Account (c)	Amount (d)		
1	Pole Attachment Rentals	746,038	172/186/454/589	3,226,634	3,311,284	830,688
2	IPP-System Upgrade Credits					
3	Defd Gain-Fiber Optics Agrmt In Kind Service-Amrtz thru 2025	954,932	124/411	674,038		280,894
4	Customer Advance Receipts	12,283,391	142	12,283,391	10,547,727	10,547,727
5	Other Deferred Credits	303,873	142/143/186	303,873	4,535,405	4,535,405
6	Contract Settlement Reserves	95,386	186	95,386		
7	CIAC/Minor Items	1,090,270	107/108	1,090,221	1,453,832	1,453,881
8	QUAL OF SVC PENALTIES - LT	222,322	426	30,860		191,462
9	Customer Donations					
10	PJM Provision True Up	13,042,897	186/229/449/456/565	20,532,060	23,871,559	16,382,396
47	TOTAL	28,739,109		38,236,463	43,719,807	34,222,453

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to amortizable property.
2. For other (Specify),include deferrals relating to other income and deductions.
3. Use footnotes as required.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance at End of Year (k)
							Debits		Credits		
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Accelerated Amortization (Account 281)										
2	Electric										
3	Defense Facilities										
4	Pollution Control Facilities	17,705,716	831,895	4,639,675							13,897,936
5	Other										
5.1	Other (provide details in footnote):										
8	TOTAL Electric (Enter Total of lines 3 thru 7)	17,705,716	831,895	4,639,675							13,897,936
9	Gas										
10	Defense Facilities										
11	Pollution Control Facilities										
12	Other										
12.1	Other (provide details in footnote):										
15	TOTAL Gas (Enter Total of lines 10 thru 14)										
16	Other										
16.1	Other - SFAS 109	[a](5,765,814)					254	38,693	254	948,937	(4,855,570)
17	TOTAL (Acct 281) (Total of 8, 15 and 16)	11,939,902	831,895	4,639,675				38,693		948,937	9,042,366
18	Classification of TOTAL										
19	Federal Income Tax	11,939,902	831,895	4,639,675				38,693		948,937	9,042,366
20	State Income Tax										
21	Local Income Tax										

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesAcceleratedAmortizationProperty

Footnote 272

Line 16 Other - Detail	Balance at Beginning of Year	Balance at End of Year
SFAS 109	(5,765,814)	(4,855,570)
Total Line 16	(5,765,814)	(4,855,570)

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization.
2. For other (Specify),include deferrals relating to other income and deductions.
3. Use footnotes as required.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance at End of Year (k)
							Debits		Credits		
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Account 282										
2	Electric	1,333,858,870	81,529,204	189,727,518				138,086,627	190		1,087,573,929
3	Gas										
4	Other (Specify)										
5	Total (Total of lines 2 thru 4)	1,333,858,870	81,529,204	189,727,518				138,086,627			1,087,573,929
6	Others	[a](166,908,388)			3,738,305	3,534,563	1823/254	14,560,614	1823/254	108,896,775	(72,368,485)
9	TOTAL Account 282 (Total of Lines 5 thru 8)	1,166,950,482	81,529,204	189,727,518	3,738,305	3,534,563		152,647,241		108,896,775	1,015,205,444
10	Classification of TOTAL										
11	Federal Income Tax	1,166,950,482	81,529,204	189,727,518	3,738,305	3,534,563		152,647,241		108,896,775	1,015,205,444
12	State Income Tax										
13	Local Income Tax										

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOtherProperty

Page 274 Footnote

	Balance at Beginning of Year	Balance at End of Year
Non-Utility	8,114,359	8,114,359
SFAS 109	(80,482,844)	(175,022,747)
Total Other - Line 6	(72,368,485)	(166,908,388)

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify),include deferrals relating to other income and deductions.
3. Provide in the space below explanations for Page 276. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance at End of Year (k)
							Debits		Credits		
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Account 283										
2	Electric										
3	NUC DECOM TRUST - SFAS 143 - ARO - BK	737,615,774	114,984,991	6,608,517							845,992,248
4	BK DEFD NUC REFUEL COSTS	11,688,371	9,237,447	11,893,443							9,032,375
5	MTM BK GAIN-A/L-TAX DEFL	(2,331,425)	1,704,384	3,019,583							(3,646,624)
6	REG ASSET-NOLC Reg Asset-Equity Carrying	(3,300,276)	2,121,329	664,671							(1,843,618)
7	SFAS 106 PST RETIRE EXP - NON-DEDUCT CONT	(6,319,292)									(6,319,292)
8	Other	(59,080,582)	37,049,815	19,129,397				20,165,034		117,162,310	55,837,112
9	TOTAL Electric (Total of lines 3 thru 8)	678,272,570	165,097,966	41,315,611				20,165,034		117,162,310	899,052,201
10	Gas										
11											
12											
13											
14											
15											
16											
17	TOTAL Gas (Total of lines 11 thru 16)										
18	TOTAL Other	[a]326,742,820			5,103,647	5,429,357	1823/254	133,899,681	1823/254	132,229,913	324,747,342
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	1,005,015,390	165,097,966	41,315,611	5,103,647	5,429,357		154,064,715		249,392,223	1,223,799,543
20	Classification of TOTAL										
21	Federal Income Tax	766,959,308	165,082,255	41,315,611	5,103,647	5,429,357		45,019,955		143,950,859	989,331,146
22	State Income Tax	238,056,082	15,711					109,044,760		105,441,364	234,468,397
23	Local Income Tax										

NOTES

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOther

Footnote Page 276

Line 18 Other - Detail	Balance at Beginning of Year	Balance at End of Year
Non-Utility 283.2	2,982,329	2,656,619
Provision Optimization	15,049,680	—
SFAS 109 283.3	308,710,811	322,090,723
Total	326,742,820	324,747,342

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	Asset Retirement Oblig-Excess Provision SFAS 143	1,721,926,426	228	211,747,036	627,092,141	2,137,271,531
2	Indiana Solar Rider	860,222	403	930,989	840,922	770,155
3	Michigan Tax Rider				468,673	468,673
4	Michigan Renewable Energy Surcharge	26,560,020	555	5,550,276	3,254,455	24,264,199
5	Over Recovered Fuel Costs - Indiana	23,201,504	440, 442, 444	24,788,662	11,901,264	10,314,106
6	PJM Exp and OSS Margin Sharing Total	14,117,442	182, 555	40,729,780	26,612,338	
7	PJM Trans Enhancement	4,002,572	142	1,962,974		2,039,598
8	SFAS 109 Deferred FIT	417,575,983	190, 282, 254	126,969,428	7,183,907	297,790,462
9	SNF Trust Funds - Pre 4/83	47,611,797	128, 224, 254	135,884,864	138,680,667	50,407,600
10	Unrealized Gain on Forward Commitments		182	93,844	1,130,618	1,036,774
11	Indiana DSM Program	16,677,450	908	1,923,630	18,200,291	32,954,111
12	PJM Transmission True-up Deferral	22,848,167	565	21,474,591	27,505,448	28,879,024
13	Cook Plant PTC Deferral - MI Portion		407	1,534,892	16,080,109	14,545,217
14	SFAS 109 Deferred SIT		190	100,400	995,474	895,074
41	TOTAL	2,295,381,583		573,691,366	879,946,307	2,601,636,524

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

Electric Operating Revenues

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.
6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See page 108, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)	MEGAWATT HOURS SOLD Year to Date Quarterly/Annual (d)	MEGAWATT HOURS SOLD Amount Previous year (no Quarterly) (e)	AVG.NO. CUSTOMERS PER MONTH Current Year (no Quarterly) (f)	AVG.NO. CUSTOMERS PER MONTH Previous Year (no Quarterly) (g)
1	Sales of Electricity						
2	(440) Residential Sales	872,163,219	828,636,245	5,300,984	5,169,204	534,662	531,024
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)	623,568,406	561,175,473	5,272,683	4,971,167	73,261	72,925
5	Large (or Ind.) (See Instr. 4)	615,626,888	588,309,598	7,297,560	7,308,668	4,765	4,803
6	(444) Public Street and Highway Lighting	5,220,807	4,896,190	48,991	54,903	1,890	1,895
7	(445) Other Sales to Public Authorities						
8	(446) Sales to Railroads and Railways						
9	(448) Interdepartmental Sales						
10	TOTAL Sales to Ultimate Consumers	[a]2,116,579,320	[d]1,983,017,506	17,920,217	17,503,941	614,578	610,647
11	(447) Sales for Resale	279,474,362	246,181,792	6,964,430	5,862,370	7	7
12	TOTAL Sales of Electricity	2,396,053,682	2,229,199,298	24,884,648	23,366,311	614,585	610,654
13	(Less) (449.1) Provision for Rate Refunds	70,518,162	13,780,316				
14	TOTAL Revenues Before Prov. for Refunds	2,325,535,520	2,215,418,982	24,884,648	23,366,311	614,585	610,654
15	Other Operating Revenues						
16	(450) Forfeited Discounts	5,858,158	5,750,618				
17	(451) Miscellaneous Service Revenues	1,387,422	1,886,385				
18	(453) Sales of Water and Water Power						
19	(454) Rent from Electric Property	18,446,525	15,275,671				
20	(455) Interdepartmental Rents						
21	(456) Other Electric Revenues	[b]19,865,576	29,156,429				
22	(456.1) Revenues from Transmission of Electricity of Others	[c]46,708,235	37,646,166				
23	(457.1) Regional Control Service Revenues	92,400	61,600				
24	(457.2) Miscellaneous Revenues						
25	Other Miscellaneous Operating Revenues						
26	TOTAL Other Operating Revenues	92,358,316	89,776,869				
27	TOTAL Electric Operating Revenues	2,417,893,836	2,305,195,851				

Line12, column (b) includes $ 28,453,475 of unbilled revenues.
Line12, column (d) includes 194,706 MWH relating to unbilled revenues

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: SalesToUltimateConsumers

Detail of unmetered Sales:

	Revenue	MWH	Average No.of Customers
Residential	2,451,244.00	12,677.00	18,268.00
Commercial	4,196,120.00	28,023.00	10,742.00
Industrial	809,226.00	5,778.00	1,322.00
Public Street Lighting	63,456.00	428.00	129.00
Total	**7,520,046.00**	**46,906.00**	**30,461.00**

(b) Concept: OtherElectricRevenue

	2024	2023
Associated Business Development	4,279,672.00	2,669,711.00
DSM Revenues	—	—
Other -Nonaffiliated		9,322.00
Misc Revenues<$250,000	4,407.00	18,230.00
Sales of Renew.Energy Credits	15,581,497.00	26,459,166.00
	19,865,576.00	**29,156,429.00**

(c) Concept: RevenuesFromTransmissionOfElectricityOfOthers

PJM Revenues

(d) Concept: SalesToUltimateConsumers

Detail of unmetered Sales:

	Revenue	MWH	Average No. of Custom
Residential	2,435,811.00	13,089.00	18,332.00
Commercial	4,224,565.00	28,922.00	10,632.00
Industrial	812,679.00	6,007.00	1,309.00
Public Street Lighting	62,268.00	428.00	126.00
Total	**7,535,323.00**	**48,446.00**	**30,399.00**

Total Sales to Ultimate Consumers include $3,204,322 of operating revenues for distribution service provided to Open Access Customers. Megawatt hours delivered to Open Access Customers were $296,141 and are included in the reported Megawatt hours sold on pg. 301 (d).

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

1. The respondent shall report below the revenue collected for each service (i.e., control area administration, market administration, etc.) performed pursuant to a Commission approved tariff. All amounts separately billed must be detailed below.

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Dispatch and Scada Services	23,100	46,200	69,300	92,400
46	TOTAL	23,100	46,200	69,300	92,400

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Medium General Service	2	4,438	0		2.2190
2	Outdoor Lighting OAD	12,678	2,451,342	0		0.1934
3	Res Off Peak Energy Storage	10,816	1,486,762	550	19,665	0.1375
4	Resi Service Opt Senior Citizen	37,101	4,843,110	6,623	5,602	0.1305
5	Residential Service	5,062,609	826,980,335	519,545	9,744	0.1634
6	Residential Service Flat	15,657	2,871,868	1,747	8,962	0.1834
7	Residential Service PEV	2,353	(694)	493	4,773	(0.0003)
8	Residential Service TOD	81,185	12,635,780	5,704	14,233	0.1556
9	Outdoor Lighting (Indiana) -OAD					
10	Unrecovered Fuel		2,473,744			
11	FAC191 fuel provisoin		4,186,661			
12	MI Credit		543,815			
41	TOTAL Billed Residential Sales	5,222,401	858,477,161	534,662	9,768	0.1644
42	TOTAL Unbilled Rev. (See Instr. 6)	78,583	13,686,058			0.1742
43	TOTAL	5,300,984	872,163,219	534,662	9,915	0.1645

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Electric Heating General	4,002	629,267	113	35,416	0.1572
2	Electric Heating Schools	5,230	647,846	13	402,308	0.1239
3	Energy Conserv Lighting	6,349	1,061,666	12	529,083	0.1672
4	GS PEV	97	12,617	10	9,700	0.1301
5	Industrial Services	1,020,308	82,685,467	57	17,900,140	0.0810
6	Irrigation Service	9,405	2,355,126	634	14,834	0.2504
7	Large General Service	2,016,817	229,720,371	3,814	528,793	0.1139
8	Large General Service OAD	2,678	139,891	2	1,339,000	0.0522
9	Large General Service OAD Self Supply	14,933	259,603	5	2,986,600	0.0174
10	Large General Service TOD	62,402	7,423,445	486	128,399	0.1190
11	Large Power	277,669	17,672,457	3	92,556,333	0.0636
12	Large Power OAD	14,933	302,206	1	14,933,000	0.0202
13	Large Power OAD Self Supply	29,250	381,446	1	29,250,000	0.0130
14	Medium General Service	1,447,151	231,391,668	63,928	22,637	0.1599
15	Medium General Service Flat	427	74,100	33	12,939	0.1735
16	Medium General Service OAD	853	47,060	9	94,778	0.0552
17	Medium General Service OAD Self Supply	2,469	61,751	14	176,357	0.0250
18	Medium General Service TOD	70,491	9,362,610	1,965	35,873	0.1328
19	Municipal and School Service	41,383	5,944,156	404	102,433	0.1436
20	Outdoor Lighting OAD	28,051	4,199,637	0		0.1497
21	Res Off Peak Energy Storage		46	0		
22	Resi Service Opt Senior Citizen		84	0		
23	Residential Service	66	13,979	0		0.2118
24	Residential Service PEV		18	0		
25	Residential Service TOD		383	0		
26	Small General Service	2,140	379,180	414	5,169	0.1772
27	Small General Service TOD	490	92,405	59	8,305	0.1886
28	Street Light Customer Owned Metered	5,410	278,680	575	9,409	0.0515
29	Street Light Service	80	24,958	4	20,000	0.3120
30	Water and Sewage Service	157,312	15,031,897	705	223,138	0.0956
31	FAC191 fuel provisoin		3,081,295			
32	Unrecovered Fuel		2,359,519			
33	Estimated	(16,331)	(1,264,078)			0.0774
41	TOTAL Billed Small or Commercial	5,204,065	614,370,756	73,261	71,035	0.1181
42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)	68,618	9,197,650			0.1340
43	TOTAL Small or Commercial	5,272,683	623,568,406	73,261	71,971	0.1183

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Electric Heating General	339	54,833	7	48,429	0.1617
2	Energy Conserv Lighting	36	4,971	1	36,000	0.1381
3	Industrial Services	5,271,555	378,349,905	157	33,576,783	0.0718
4	Large General Service	1,066,802	131,094,259	1,060	1,006,417	0.1229
5	Large General Service OAD Self Supply	136	19,654	1	136,000	0.1445
6	Large General Service TOD	2,879	393,040	7	411,286	0.1365
7	Large Power	266,604	26,066,958	17	15,682,588	0.0978
8	Large Power OAD	3,912	198,739	1	3,912,000	0.0508
9	Large Power OAD Self Supply	203,780	1,283,744	5	40,756,000	0.0063
10	Medium General Service	380,197	61,047,385	3,437	110,619	0.1606
11	Medium General Service Flat	265	70,629	2	132,500	0.2665
12	Medium General Service OAD	6,117	386,181	10	611,700	0.0631
13	Medium General Service OAD Self Supply	261	13,776	3	87,000	0.0528
14	Medium General Service TOD	1,610	218,028	44	36,591	0.1354
15	Outdoor Lighting OAD	5,782	809,638			0.1400
16	Resi Service Opt Senior Citizen		41			
17	Residential Service		303			
18	Small General Service	60	9,313	6	10,000	0.1552
19	Water and Sewage Service	4,114	398,764	7	587,714	0.0969
20	Estimated	35,721	1,993,071			
21	FAC191 fuel provisoin		3,481,736			
22	Unrecovered Fuel		4,180,667			
41	TOTAL Billed Large (or Ind.) Sales	7,250,170	610,075,635	4,765	1,521,547	0.0841
42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)	47,390	5,551,253			0.1171
43	TOTAL Large (or Ind.)	7,297,560	615,626,888	4,765	1,531,492	0.0844

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Energy Conserv Lighting	17,622	2,772,291	215	81,963	0.1573
2	Ft Wayne Street Lighting	15,387	512,055	1	15,387,000	0.0333
3	Medium General Service	2,750	709,453	1,057	2,602	0.2580
4	Medium General Service TOD	154	31,577	40	3,850	0.2050
5	Municipal and School Service	210	39,068	33	6,364	0.1860
6	Outdoor Lighting OAD	428	63,456			0.1483
7	Residential Service		252			
8	Residential Service TOD		9			
9	Small General Service	148	27,784	69	2,145	0.1877
10	Street Light Customer Owned Metered	5,413	276,692	396		
11	Street Light Service	6,766	729,657	79		
12	FAC191 fuel provisoin		23,251			
13	Unrecovered Fuel		16,747			
41	TOTAL Billed Public Street and Highway Lighting	48,878	5,202,292	1,890	25,861	0.1064
42	TOTAL Unbilled Rev. (See Instr. 6)	113	18,515			0.1638
43	TOTAL	48,991	5,220,807	1,890	25,921	0.1066

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed Provision For Rate Refunds					
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL		70,518,162			

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
41	TOTAL Billed - All Accounts	17,725,514	2,088,125,844	614,578	28,842	0.1178
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts	194,704	28,453,476			0.1461
43	TOTAL - All Accounts	17,920,218	2,116,579,320	614,578	28,842	0.1181

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

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

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

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

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

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

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

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

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (g) through (k).
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,line 24.
10. Footnote entries as required and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	ACTUAL DEMAND (MW)		Megawatt Hours Sold (g)	REVENUE			Total ($) (h+i+j) (k)
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)		Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	
1	CITY OF AUBURN	RQ	NOTE 1 [2]				296,351	12,948,558	8,529,990		21,478,548
2	CITY OF DOWAGIAC, MI	RQ	NOTE 1				56,953	2,759,831	1,403,856		4,163,687
3	INDIANA MUNICIPAL POWER AGENCY	RQ	NOTE 1				1,591,840	59,207,648	47,565,334		106,772,982
4	PJM INTERCONNECTION	OS	NOTE 1				4,198,497	(871,329)	129,399,106		128,527,777
5	PJM INTERCONNECTION	RQ	NOTE 1				0			(49,645,947)	(49,645,947)
6	RBC CAPITAL MARKET, LLC	OS	NOTE 1				0		(5,284)		(5,284)
7	WABASH VALLEY POWER ASSN INC.	RQ	NOTE 1				820,789	38,048,699	30,155,135		68,203,834
8	WELLS FARGO SECURITIES, LLC	OS	NOTE 1				0		(21,235)		(21,235)
15	Subtotal - RQ						2,765,933	112,964,736	87,654,315	(49,645,947)	150,973,104
16	Subtotal-Non-RQ						4,198,497	(871,329)	129,372,587		128,501,258
17	Total						6,964,430	112,093,407	217,026,902	(49,645,947)	279,474,362

FOOTNOTE DATA

(a) Concept: RateScheduleTariffNumber

FERC Electric Tariff, First Revised Volume No. 5.

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	2,408,481	2,680,530
5	(501) Fuel	[b]49,624,544	28,393,142
6	(502) Steam Expenses	16,397,416	5,472,905
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	873,399	958,664
10	(506) Miscellaneous Steam Power Expenses	2,606,618	1,616,807
11	(507) Rents	15,296	14,884
12	(509) Allowances	3,626,223	2,952,358
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	75,551,977	42,089,290
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	688,839	854,365
16	(511) Maintenance of Structures	517,848	493,190
17	(512) Maintenance of Boiler Plant	3,015,738	3,594,851
18	(513) Maintenance of Electric Plant	1,320,481	1,970,081
19	(514) Maintenance of Miscellaneous Steam Plant	359,736	406,306
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	5,902,642	7,318,793
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)	81,454,618	49,408,083
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	22,203,816	12,369,910
25	(518) Fuel	[b]108,260,991	99,235,736
26	(519) Coolants and Water	9,932,181	5,271,579
27	(520) Steam Expenses	11,972,646	11,722,657
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses	5,329,268	5,346,518
31	(524) Miscellaneous Nuclear Power Expenses	[b]65,730,175	78,272,038
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)	223,429,077	212,218,438
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	5,104,817	3,043,915
36	(529) Maintenance of Structures	5,121,256	4,540,865
37	(530) Maintenance of Reactor Plant Equipment	87,850,412	86,119,652
38	(531) Maintenance of Electric Plant	15,999,419	18,474,235
39	(532) Maintenance of Miscellaneous Nuclear Plant	22,605,800	23,682,415
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	136,681,704	135,861,082
41	TOTAL Power Production Expenses-Nuclear. Power (Enter Total of lines 33 & 40)	360,110,781	348,079,520
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	192,023	398,042
45	(536) Water for Power		
46	(537) Hydraulic Expenses	24,283	70,653
47	(538) Electric Expenses	31,437	32,460
48	(539) Miscellaneous Hydraulic Power Generation Expenses	1,179,724	873,342

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
49	(540) Rents	1,011	338
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	1,428,478	1,374,835
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	170,058	149,028
54	(542) Maintenance of Structures	762,671	924,603
55	(543) Maintenance of Reservoirs, Dams, and Waterways	193,076	331,616
56	(544) Maintenance of Electric Plant	1,726,519	313,215
57	(545) Maintenance of Miscellaneous Hydraulic Plant	29,893	22,495
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	2,882,217	1,740,957
59	TOTAL Power Production Expenses-Hydraulic Power (Total of Lines 50 & 58)	4,310,696	3,115,792
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	18,591	18,688
63	(547) Fuel		
64	(548) Generation Expenses	960	1,075
64.1	(548.1) Operation of Energy Storage Equipment		
65	(549) Miscellaneous Other Power Generation Expenses	55,149	(42,220)
66	(550) Rents	17	18
67	TOTAL Operation (Enter Total of Lines 62 thru 67)	74,717	(22,439)
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures		
71	(553) Maintenance of Generating and Electric Plant	276,734	301,373
71.1	(553.1) Maintenance of Energy Storage Equipment		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant		
73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)	276,734	301,373
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)	351,451	278,934
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	363,982,191	325,674,558
76.1	(555.1) Power Purchased for Storage Operations		
77	(556) System Control and Load Dispatching	924,430	1,040,136
78	(557) Other Expenses	2,527,805	3,390,011
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	367,434,426	330,104,705
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74 & 79)	813,661,972	730,987,034
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	6,476,044	6,570,710
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	254,741	173,831
87	(561.3) Load Dispatch-Transmission Service and Scheduling	4,587	
88	(561.4) Scheduling, System Control and Dispatch Services	5,349,138	4,813,644
89	(561.5) Reliability, Planning and Standards Development	149,845	166,641
90	(561.6) Transmission Service Studies		(7)
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	1,710,292	1,390,481
93	(562) Station Expenses	[d]738,351	557,138
93.1	(562.1) Operation of Energy Storage Equipment		
94	(563) Overhead Lines Expenses	281,859	349,292
95	(564) Underground Lines Expenses	4,987	2,773
96	(565) Transmission of Electricity by Others	261,665,236	233,472,032
97	(566) Miscellaneous Transmission Expenses	3,064,599	1,787,600
98	(567) Rents	761,489	773,183
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	280,461,168	250,057,318
100	Maintenance		

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
101	(568) Maintenance Supervision and Engineering	133,680	64,525
102	(569) Maintenance of Structures	40,173	43,743
103	(569.1) Maintenance of Computer Hardware	[a]18,413	23,696
104	(569.2) Maintenance of Computer Software	747,180	624,204
105	(569.3) Maintenance of Communication Equipment	104,861	41,361
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	2,162,504	1,799,156
107.1	(570.1) Maintenance of Energy Storage Equipment		
108	(571) Maintenance of Overhead Lines	10,980,340	12,058,216
109	(572) Maintenance of Underground Lines	16,954	22,633
110	(573) Maintenance of Miscellaneous Transmission Plant	18,341	16,418
111	TOTAL Maintenance (Total of Lines 101 thru 110)	14,222,446	14,693,952
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	294,683,614	264,751,270
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services	6,052,433	4,495,433
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	6,052,433	4,495,433
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Operation Expenses (Enter Total of Lines 123 and 130)	6,052,433	4,495,433
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	2,951,498	1,736,769
135	(581) Load Dispatching	262,235	275,193
136	(582) Station Expenses	1,227,290	1,081,702
137	(583) Overhead Line Expenses	3,646,855	2,746,618
138	(584) Underground Line Expenses	5,249,562	4,459,018
138.1	(584.1) Operation of Energy Storage Equipment		
139	(585) Street Lighting and Signal System Expenses	64,675	76,255
140	(586) Meter Expenses	743,782	1,709,527
141	(587) Customer Installations Expenses	474,200	579,781
142	(588) Miscellaneous Expenses	18,239,701	13,260,867
143	(589) Rents	2,055,217	2,115,795
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	34,915,015	28,041,525
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	73,840	79,409
147	(591) Maintenance of Structures	39,629	14,754
148	(592) Maintenance of Station Equipment	961,845	1,428,747
148.1	(592.2) Maintenance of Energy Storage Equipment		
149	(593) Maintenance of Overhead Lines	56,250,800	59,069,903
150	(594) Maintenance of Underground Lines	878,311	1,088,631
151	(595) Maintenance of Line Transformers	390,449	377,679
152	(596) Maintenance of Street Lighting and Signal Systems	202,105	138,353

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
153	(597) Maintenance of Meters	92,315	61,737
154	(598) Maintenance of Miscellaneous Distribution Plant	730,117	568,618
155	TOTAL Maintenance (Total of Lines 146 thru 154)	59,619,411	62,827,831
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)	94,534,426	90,869,356
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	525,751	803,797
160	(902) Meter Reading Expenses	973,107	1,280,349
161	(903) Customer Records and Collection Expenses	14,956,829	14,375,371
162	(904) Uncollectible Accounts	158,495	82,036
163	(905) Miscellaneous Customer Accounts Expenses	52,123	62,151
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	16,666,305	16,603,704
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	900,597	917,830
168	(908) Customer Assistance Expenses	43,974,564	42,479,566
169	(909) Informational and Instructional Expenses		
170	(910) Miscellaneous Customer Service and Informational Expenses	5,207	27,057
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	44,880,368	43,424,453
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	146,399	96,130
176	(913) Advertising Expenses	234,605	284,671
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)	381,004	380,801
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	42,045,744	42,782,629
182	(921) Office Supplies and Expenses	3,487,307	2,732,440
183	(Less) (922) Administrative Expenses Transferred-Credit	7,039,443	5,939,108
184	(923) Outside Services Employed	13,375,237	5,091,302
185	(924) Property Insurance	(f)241,603	3,138,017
186	(925) Injuries and Damages	7,730,836	3,996,762
187	(926) Employee Pensions and Benefits	16,481,275	(336,904)
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	20,512,199	20,762,688
190	(929) (Less) Duplicate Charges-Cr.	1,433,444	1,150,177
191	(930.1) General Advertising Expenses	130,958	83,001
192	(930.2) Miscellaneous General Expenses	5,472,288	5,182,047
193	(931) Rents	2,655,292	2,620,351
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	103,659,852	78,963,048
195	Maintenance		
196	(935) Maintenance of General Plant	11,382,355	10,193,046
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196)	115,042,207	89,156,094
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 156, 164, 171, 178, and 197)	1,385,902,329	1,240,668,145

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: FuelSteamPowerGeneration

The portion of account 501 that is excluded from the fuel costs in I&M's generation formula rate is identified by a query of the general ledger.

(b) Concept: NuclearFuelExpense

The portion of account 518 that is exclude from the nuclear fuel costs in I&M's generation formula rate is identified by a query of the general ledger

(c) Concept: MiscellaneousNuclearPowerExpenses

The portion of account 524 representing ARO expense that are excluded from non-fuel generation formula rate is identified by a query of the general ledger.The nuclear decommissioning expense allowed in the formula is an amount approved by the Indiana utility Regulatory Commission

(d) Concept: StationExpensesTransmissionExpense

Generation Step-Up Units' (GSU's) O&M expenses included in I&M's generation formula rates are the ratio of GSU balances to all investment for plant accounts 352 & 353 mutiplied by the balance in O&M accounts 562, 569, & 570.

(e) Concept: MaintenanceOfComputerHardwareTransmission

Allocated maintenance expenses for joint use computer hardware, computer software and communication equipment are determined by using various factors, which include number of remote terminal units, number of radios, number of employees and other factors assigned to each function.

(f) Concept: PropertyInsurance

The insurance expenses for generation included in I&M's generation formula rate are identified by a query of the general ledger.

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

PURCHASED POWER (Account 555)

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

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	Ferc Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)		MegaWatt Hours Purchased (Excluding for Energy Storage) (g)	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES		COST/SETTLEMENT OF POWER			
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)			MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total (k+l+m) o Settlemer ($) (n)
1	[g] AEP GENERATING COMPANY	RQ					1,476,405				76,044,839	49,630,624		125,675,4
2	City of Winchester, IN	OS					0					19,638		19,6
3	Fowler Ridge II Wind Farm LLC	OS					132,269					13,606,410		13,606,4
4	Fowler Ridge Wind Farm LLC	OS					209,660					15,231,379		15,231,3
5	French Paper	OS					199					48,334		48,3
6	Headwaters Wind Farm LLC	OS					617,776					31,565,663		31,565,6
7	OVEC Power Scheduling	OS					781,254				37,358,766	29,474,956		66,833,7
8	Wildcat Wind farm	OS					332,702					18,319,480		18,319,4
9	Constellation Engy Commodities	OS					0					23,751		23,7
10	[h] OVER/UNDER PJM EXP TRACKER	OS					0					(16,646,214)		(16,646,21
11	[c] OVER/UNDER RESOURCE ADEQUACY RIDER	OS					1,867				720,605	405,904		1,126,5
12	PJM INTERCONNECTION	OS					2,875,524				1,720,497	101,673,288		103,393,7
13	Wells Fargo Securities, LLC	OS										4,783,523		4,783,5

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	Ferc Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)		MegaWatt Hours Purchased (Excluding for Energy Storage) (g)	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES		COST/SETTLEMENT OF POWER			
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)			MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total (k+l+m) o Settlemer ($) (n)
14	Evolution Markets Futures, LLC	OS										748		7
15	TOTAL						6,427,656	0	0	0	115,844,707	248,137,484		363,982,1

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Affiliated Company
(b) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Per the IURC's Order in Cause No. 45235, I&M tracks the recovery of certain costs and revenues related to I&M's membership in PJM compared to the level in base rates.
(c) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Over-/Under-recovery accounting to track incremental changes in the Company's purchased power costs, per the IURC's Order in Cause No. 45235.

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1) (Including transactions referred to as "wheeling")

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c).
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.
9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (0) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)	Ferc Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS			
									Megawatt Hours Received (i)	Megawatt Hours Delivered (j)	Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total Revenues ($) (k+l+m) (n)
1	PJM Network Integ Rev - Affil	Various	Various	FNO	(a) PJM OATT	Various	Various				4,851,749			4,851,749
2	PJM Network Integ Trans Rev Whlsle	Various	Various	FNO	PJM OATT	Various	Various				5,659,137			5,659,137
3	PJM Network Integ Trans Serv	Various	Various	FNO	PJM OATT	Various	Various				25,235,901			25,235,901
4	PJM Point to Point Trans Service	Various	Various	LFP	PJM OATT	Various	Various				5,362,776			5,362,776
5	PJM Power Factor Credits Rev Nonaffiliated	Various	Various	OS	PJM OATT	Various	Various						443,259	443,259
6	PJM Power Factor Credits Rev Whlsle	Various	Various	OS	PJM OATT	Various	Various						20,703	20,703
7	PJM Trans Distribution & Metering	Various	Various	OS	PJM OATT	Various	Various						806,813	806,813
8	PJM Trans Enhancement Rev	Various	Various	FNO	PJM OATT	Various	Various				4,057,457			4,057,457
9	PJM Trans Enhancement Rev - Affil	Various	Various	FNO	PJM OATT	Various	Various							
10	PJM Trans Enhancement Rev Whlsle	Various	Various	FNO	PJM OATT	Various	Various				123,990			123,990
11	PJM Trans Owner Admin Rev - Affil	Various	Various	OLF	PJM OATT	Various	Various							
12	PJM Trans Owner Admin Revenue	Various	Various	OLF	PJM OATT	Various	Various					132,455		132,455
13	PJM Trans Owner Serv Rev Whlsle	Various	Various	OLF	PJM OATT	Various	Various					13,996		13,996
35	TOTAL										45,291,009	146,451	1,270,775	46,708,235

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: RateScheduleTariffNumber

Effective October 1, 2004, the administration of the transmission tariff was turned over to PJM. PJM does not provide any detail except for the total revenue by the major classes listed. OATT (Open Access Transmission Tariff) 3rd revised Volume No. 6

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO – Firm Network Service for Others, FNS – Firm Network Transmission Service for Self, LFP – Long-Term Firm Point-to-Point Transmission Service, OLF – Other Long-Term Firm Transmission Service, SFP – Short-Term Firm Point-to-Point Transmission Reservation, NF – Non-Firm Transmission Service, OS – Other Transmission Service and AD- Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
4. In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tariff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tariff (d)	Total Revenue (e)
44					
45					
46					
47					
48					
49					
40	TOTAL				

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter ""TOTAL"" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			MegaWatt Hours Received (c)	MegaWatt Hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	PJM Enhancements	OS	0	0			[a]23,326,889	23,326,889
2	PJM-Trans Owner Serv	OS	0	0			[b]727,332	727,332
3	PJM NITS	OS	0	0			[c]237,611,016	237,611,016
	TOTAL		0	0			261,665,237	261,665,237

FOOTNOTE DATA

(a) Concept: OtherChargesTransmissionOfElectricityByOthers

Transmission Enhancement Charges and Credits (PJM OATT Schedule 12)

(b) Concept: OtherChargesTransmissionOfElectricityByOthers

(PJM OATT Schedule H)

(c) Concept: OtherChargesTransmissionOfElectricityByOthers

(PJM OATT Tariff Sixth Revised Volume No.1)

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	3,734,592
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	2,222
4	Pub and Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn greater than or equal to 5,000 show purpose, recipient, amount. Group if less than $5,000	
6	Associated Business Development	887,670
7	American Electric Power Service Corp Billings	913,012
8	Corporate Money Pool Allocations	16,575
9	Corporate Legal and Financing	69,505
10	Corporate Contributions and Memberships	109,455
11	Intercompany Billings	(282,985)
12	Minor iItems	22,242
46	TOTAL	5,472,288

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

Depreciation and Amortization of Electric Plant (Account 403, 404, 405)

1. Report in section A for the year the amounts for: (b) Depreciation Expense (Account 403); (c) Depreciation Expense for Asset Retirement Costs (Account 403.1); (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section B the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
   Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
   In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
   For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type of mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			48,305,420		48,305,420
2	Steam Production Plant	91,249,820	2,228,801	11,359		93,489,980
3	Nuclear Production Plant	166,081,617	242,810			166,324,427
4	Hydraulic Production Plant-Conventional	2,904,465	12,201			2,916,666
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	3,039,238				3,039,238
7	Transmission Plant	50,209,645				50,209,645
8	Distribution Plant	97,721,821				97,721,821
9	Regional Transmission and Market Operation					
10	General Plant	8,602,206	33,925	259,450		8,895,581
11	Common Plant-Electric					
12	TOTAL	419,808,812	2,517,737	48,576,229		470,902,778

B. Basis for Amortization Charges

Section A, Line 1, Column D represents amortization of franchises over the life of the franchise, amorization of capitalized software development cost over a 5 year life and the amortization of costs associated with the Oracle strategic partnership over a 10 year life. Section A, Line 2, Column D represents amortization of Rockport Unit 2 Leasehold Improvements over the life of Rockport Unit 2 Lease. Section A, Line 10, Column D represents amortization of leasehold improvements over the lives of the related assets.

Line No.	C. Factors Used in Estimating Depreciation Charges						
	Account No. (a)	Depreciable Plant Base (in Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. Rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	STEAM						
13	311 - Rockport U1	83.591	44 years	8%	7.6%		
14	311 - Rockport U2	28.279	39 years	8%	7.6%		
15	311 - Rkpt DSI U1	2.905	44 years	8%	7.6%		
16	311 - Rkpt DSI U2	0.787	39 years	8%	7.6%		
17	312 - Rockport ACI	24.807	44 years	8%	8.98%		
18	312 - Rockport U1	11.839	44 years	8%	8.98%		
19	312 - Rockport U2	426.786	39 years	8%	8.98%		
20	312 - Rockport U1 -SCR	26.261	44 years	8%	8.98%		
21	312 - Rockport U2 -SCR	51.747	39 years	8%	8.98%		
22	312 - Rkpt DSI U1	138.434	44 years	8%	8.98%		
23	312 - Rkpt DSI U1 - Pre	54.117	44 years	8%	8.98%		
24	312 - Rkpt DSI U2	110.88	39 years	8%	8.98%		
25	314 - Rockport U1	105.943	44 years	8%	8.29%		
26	314 - Rockport U2	0.867	39 years	8%	8.29%		
27	315 - Rockport U1	59.293	44 years	8%	7.43%		
28	315 - Rockport U2	2.088	39 years	8%	7.43%		
29	316 - Rockport U1	18.304	44 years	8%	8.02%		
30	316 - Rockport U1-SCR	0.008	44 years	8%	8.02%		
31	316 - Rockport U2	6.845	39 years	8%	8.02%		
32	TOTAL STEAM	1,153.781					
33	NUCLEAR						
34	321 - Cook U1	92.719	59 years	1%	3.78%		
35	321 - Cook U2	386.25	59 years	2%	3.78%		
36	322 - Cook U1	773.77	59 years	2%	5.05%		
37	322 - Cook U2	1,025.409	59 years	3%	4.46%		
38	323 - Cook U1	307.215	59 years	2%	5.52%		
39	323 - Cook U2	418.652	59 years	3%	5.05%		
40	324 - Cook U1	145.4	59 years		4.63%		
41	324 - Cook U2	207.989	59 years		4.47%		
42	325 - Cook U1	36.584	59 years		4.96%		
43	325 - Cook U2	279.031	59 years		4.51%		
44	TOTAL NUCLEAR	3,673.019					
45	HYDRO						
46	331 - Berrien Springs	2.056	128 years	3%	6.22%		
47	331 - Buchanan	0.744	117 years	5%	4.77%		
48	331 - Constantine	0.452	132 years	20%	2.94%		
49	331 - Crew Service Center	0.417		4%	1.86%		
50	331 - Elkhart	1.049	117 years	3%	10.03%		
51	331 - Mottville	1.468	110 years	3%	5.99%		
52	331 - Twin Branch	1.143	132 years	3%	5.85%		
53	332 - Berrien Springs	5.409	128 years	3%	4.23%		
54	332 - Buchanan	4.724	117 years	5%	4.07%		
55	332 - Constantine	1.229	132 years	20%	2.85%		
56	332 - Elkhart	7.204	117 years	3%	10.61%		
57	332 - Mottville	2.166	110 years	3%	5.42%		
58	332 - Twin Branch	5.129	132 years	3%	5.19%		
59	333 - Berrien Springs	7.192	128 years	3%	4.56%		
60	333 - Buchanan	1.67	117 years	5%	4.22%		
61	333 - Constantine	1.099	132 years	20%	2.82%		
62	333 - Elkhart	0.618	117 years	3%	9.04%		
63	333 - Mottville	1.014	110 years	3%	5.23%		
64	333 - Twin Branch	6.094	132 years	3%	5.47%		

Line No.	C. Factors Used in Estimating Depreciation Charges						
	Account No. (a)	Depreciable Plant Base (in Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. Rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
65	334 - Berrien Springs	1.679	128 years	3%	4.46%		
66	334 - Buchanan	1.032	117 years	5%	4.23%		
67	334 - Constantine	1.137	132 years	20%	3.42%		
68	334 - Elkhart	1.178	117 years	3%	9.21%		
69	334 - Mottville	0.749	110 years	3%	5.98%		
70	334 - Twin Branch	1.995	132 years	3%	5.42%		
71	335 - Berrien Springs	1.025	128 years	3%	4.74%		
72	335 - Buchanan	0.292	117 years	5%	4.77%		
73	335 - Constantine	0.461	132 years	20%	3.42%		
74	335 - Crew Service Center	0.127		4%	1.85%		
75	335 - Elkhart	0.224	117 years	3%	11.53%		
76	335 - Mottville	0.482	110 years	3%	6.71%		
77	335 - Twin Branch	0.844	132 years	3%	6.28%		
78	336 - Mottville	0.001	110 years	3%	4.49%		
79	TOTAL HYDRO	62.103					
80	OTHER GENERATION						
81	341 - Olive Solar	0.401	20 years	4%	5.33%		
82	341 South Bend Solar	0.054	30 years	2%	3.42%		
83	341 Twin Branch Solar	0.021	20 years	4%	5.35%		
84	341 - Watervliet Solar	0.379	20 years	4%	5.33%		
85	344 - Deer Creek Solar	5.668	20 years	3%	5.31%		
86	344 - Olive Solar	11.185	20 years	4%	5.33%		
87	344 - South Bend Solar	28.73	30 years	2%	3.42%		
88	344 - Twin Branch Solar	6.955	20 years	4%	5.35%		
89	344 - Watervliet Solar	11.107	20 years	4%	5.33%		
90	345 - Deer Creek Solar	0.797	20 years	3%	6.55%		
91	345 - Olive Solar	0.269	20 years	4%	5.33%		
92	345 - South Bend Solar	3.999	30 years	2%	3.42%		
93	345 - Twin Branch Solar	0.01	20 years	4%	5.35%		
94	345 - Watervliet Solar	0.012	20 years	4%	5.37%		
95	346 - Deer Creek Solar	0.015	20 years	3%	6.57%		
96	346 - Olive Solar	0.215	20 years	4%	5.33%		
97	346 - South Bend Solar	0.347	30 years	2%	3.42%		
98	346 - Watervliet Solar	0.047	20 years	4%	5.35%		
99	346 - Twin Branch Solar	0.358	20 years	4%	5.37%		
100	TOTAL OTHER	70.569					
101	TRANSMISSION						
102	350 (Rights)	65.877	65 years		1.76%	R5	
103	352	101.866	60 years	8%	1.86%	L2	
104	353	894.576	44 years	11%	2.71%	L1	
105	353.16	16.518	44 years	11%	2.71%	L1	
106	354	230.476	66 years	39%	2.79%	R5	
107	355	282.509	50 years	63%	3.35%	L0	
108	356	318.174	67 years	34%	2.29%	R4	
109	356.16	0.561	67 years	34%	2.29%	R4	
110	357	11.981	55 years		1.88%	R5	
111	358	9.54	55 years	12%	2.14%	L1.5	
112	358.16	0.003	55 years	12%	2.14%	L1.5	
113	359	0.091	65 years		1.69%	R5	
114	TOTAL TRANSMISSION	1,932.172					
115	DISTRIBUTION						
116	360 (Rights) - IN	14.277	65 years		1.5%	R5	
117	360 (Rights) - MI	6.77	65 years		1.52%	R5	

Line No.	C. Factors Used in Estimating Depreciation Charges						
	Account No. (a)	Depreciable Plant Base (in Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. Rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
118	361 - IN	69.913	65 years	48%	2.38%	L1.5	
119	361 - MI	10.964	65 years	48%	2.4%	L1.5	
120	362 - IN	473.357	47 years	18%	2.62%	L0	
121	362 - MI	124.352	43 years	18%	2.93%	L0.5	
122	362.16 - IN	18.382	47 years	18%	2.62%	L0	
123	362.16 - MI	2.708	43 years	18%	2.93%	L0.5	
124	363 - IN	0.107	15 years		9.61%	SQ	
125	364 - IN	350.944	54 years	100%	3.45%	L0	
126	364 - MI	126.313	42 years	100%	4.6%	L0	
127	365 - IN	550.204	48 years	23%	2.45%	L0	
128	365 - MI	184.804	41 years	23%	3%	L0	
129	366 - IN	208.762	76 years		1.26%	R1.5	
130	366 - MI	23.516	62 years		1.57%	R2	
131	367 - IN	305.243	61 years		1.62%	R1	
132	367 - MI	44.272	57 years		1.51%	R1	
133	368 - IN	419.912	43 years	8%	1.89%	R0.5	
134	368 - MI	69.179	27 years	8%	3.71%	R0.5	
135	369 - IN	207.199	45 years	26%	2.62%	R0.5	
136	369 - MI	40.468	45 years	26%	2.63%	R0.5	
137	370 - IN	46.366	15 years	17%	6.72%	L0	
138	370 - MI	4.304	15 years	17%	8.24%	L0	
139	370 - AMI	3.715			10%		
140	370 AMI - IN	107.527	15 years	17%	6.72%	L0	
141	370 AMI - MI	24.434	15 years	17%	8.24%	L0	
142	371 - IN	24.641	18 years	23%	4.63%	L0	
143	371 - MI	9.266	18 years	23%	4.07%	L0	
144	373 - IN	21.101	22 years	19%	4.66%	R0.5	
145	373 - MI	5.935	22 years	19%	6.46%	R0.5	
146	TOTAL DISTRIBUTION	3,498.935					
147	GENERAL PLANT						
148	390	128.243	45 years	4%	2.45%	L1	
149	391	7.777	22 years	(2)%	5.58%	SQ	
150	392	0.199	20 years		5.1%	SQ	
151	393	1.56	14 years		7.95%	SQ	
152	394	22.962	16 years		7.48%	SQ	
153	395	0.578	20 years	(1)%	5.93%	SQ	
154	396	0.544	25 years	2%	6.91%	SQ	
155	397	79.192	27 years	4%	4.29%	SQ	
156	397.16	5.002	27 years	4%	4.29%	SQ	
157	398	15.024	30 years	(5)%	3.71%	SQ	
158	TOTAL GENERAL PLANT	261.081					
159	DEPRECIABLE SUM	[a]10,651.66					

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: DepreciablePlantBase

The depreciable plant base is the November 30, 2024 total company depreciable plant.

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.
3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in columns (f), (g), and (h), expenses incurred during the year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

						EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR		
						CURRENTLY CHARGED TO						
Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expenses for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)	Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)
1	Nuclear Regulatory Commission - Inspection and Licensing Fees	2,384,562		2,384,562			928	2,384,576				
2	Nuclear Regulatory Commission - Annual Fees	11,278,500		11,278,500			928	11,278,500				
3	State Commission Fees - Indiana	2,476,344		2,476,344			928	2,476,344				
4	State Commission Fees - Michigan	1,050,782		1,050,782			928	1,050,782				
5	Integrated Resource Plan Filing - Michigan		421,143	421,143			928	421,144				
6	Integrated Resource Plan Filing - Indiana		913,485	913,485			928	913,485				
7	Indiana Rate Case		462,924	462,924	757,326		928	89,905	115,368	928	373,019	499,675
8	Michigan Rate Case		1,336,020	1,336,020	906,579		928	1,241,309	(77,579)	928	94,711	734,289
9	Fuel Cost Recovery		61,160	61,160			928	61,161				
10	Power Supply Cost Recovery		40,299	40,299			928	40,299				
11	Minor Items < $25,000		86,980	86,980			928	86,964				
46	TOTAL	17,190,188	3,322,011	20,512,199	1,663,905			20,044,469	37,789		467,730	1,233,964

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D and D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D and D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:
   Classifications:

   A. Electric R, D and D Performed Internally:
      1. Generation
         a. hydroelectric
            i. Recreation fish and wildlife
            ii. Other hydroelectric
         b. Fossil-fuel steam
         c. Internal combustion or gas turbine
         d. Nuclear
         e. Unconventional generation
         f. Siting and heat rejection
      2. Transmission
         a. Overhead
         b. Underground
      3. Distribution
      4. Regional Transmission and Market Operation
      5. Environment (other than equipment)
      6. Other (Classify and include items in excess of $50,000.)
      7. Total Cost Incurred

   B. Electric, R, D and D Performed Externally:
      1. Research Support to the electrical Research Council or the Electric Power Research Institute
      2. Research Support to Edison Electric Institute
      3. Research Support to Nuclear Power Groups
      4. Research Support to Others (Classify)
      5. Total Cost Incurred

3. Include in column (c) all R, D and D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D and D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D and D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e).
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D and D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by ""Est.""
7. Report separately research and related testing facilities operated by the respondent.

Line No.	Classification (a)	Description (b)	Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation (g)
					Amounts Charged In Current Year: Account (e)	Amounts Charged In Current Year: Amount (f)	
1	A(1)b: Generation: Fossil Fuel Steam	Generation Program Management	74,333		506,524	74,333	
2		2 items < $50,000	2,129		506	2,129	
3	A(1)d: Nuclear	1 item <$50,000	2,354		524	2,354	
4	A(1)e: Generation: Unconventional	1 item <$50,000	225		506	225	
5	A(2): Transmission	1 item <$50,000	2,540		566	2,540	
6	A(3): Distribution	1 item <$50,000	3,290		588	3,290	
7	A(5): Environment (other than equipment)	1 items <$50,000	24,972		506	24,972	
8	A(6): Other	2 items <$50,000	543		506,524,566,588	543	
9	A(6)f: Other: Metering	1 item <$50,000	1,851		588	1,851	
10	A(6)g: Research-General	1 item <$50,000	1,338		566,588	1,338	
11	A(7) TOTAL COSTS INCURRED INTERNALLY		113,575			113,575	
12	B: Electric R&D External	4 items <$50,000		28,581	506,524,566,588	28,581	
13	B(1): Research Support to Electric Research	EPRI Research Portfolio		243,826	506,566,588	243,826	
14		EPRI Nuclear Annual Research		773,607	524	773,607	
15		IT - EPRI Annual Research Port		55,693	506,524,566,588	55,693	
16		EPRI Environmental Science		45,125	506	45,125	
17		19 items <$50,000		48,292	506,524,566,588	48,292	
18	(B4): Steam Power	1 item <$50,000		538	506	538	
19	B(5) TOTAL COSTS INCURRED EXTERNALLY			1,195,662		1,195,662	

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	89,056,942		
4	Transmission	3,398,439		
5	Regional Market			
6	Distribution	11,625,514		
7	Customer Accounts	1,611,020		
8	Customer Service and Informational	2,487,585		
9	Sales			
10	Administrative and General	2,413,435		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	110,592,935		
12	Maintenance			
13	Production	47,072,274		
14	Transmission	2,273,992		
15	Regional Market			
16	Distribution	12,742,485		
17	Administrative and General	1,552,212		
18	TOTAL Maintenance (Total of lines 13 thru 17)	63,640,963		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	136,129,216		
21	Transmission (Enter Total of lines 4 and 14)	5,672,431		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	24,367,999		
24	Customer Accounts (Transcribe from line 7)	1,611,020		
25	Customer Service and Informational (Transcribe from line 8)	2,487,585		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	3,965,647		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	174,233,898	7,976,190	182,210,088
29	Gas			
30	Operation			
31	Production - Manufactured Gas			
32	Production-Nat. Gas (Including Expl. And Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production - Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	174,233,898	7,976,190	182,210,088
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	58,194,234	2,664,052	60,858,286
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	58,194,234	2,664,052	60,858,286
72	Plant Removal (By Utility Departments)			
73	Electric Plant	9,970,075	456,416	10,426,491
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	9,970,075	456,416	10,426,491
77	Other Accounts (Specify, provide details in footnote):			
78	Other Accounts (Specify, provide details in footnote):			
79	120 - Nuclr Fuel in Proc of Refinmnt	476,764		476,764
80	121 - Nonutility Property - WIP	1,145		1,145
81	122 - Depr and Amortization	244		244
82	152 - Fuel Stock Undistributed	2,359,836		2,359,836
83	154 - Materials and Supplies	6,850		6,850
84	163 - Stores Expense Undistributed	8,074,527	(8,074,527)	
85	183 - Prelim Survey	(39,979)	39,979	
86	184 - Clearing Accounts	3,062,110	(3,062,110)	
87	185 - ODD Temporary Facilities	136,841		136,841
88	186 - Misc Deferred Debits	1,945,160		1,945,160
89	228 - RAD Waste Accrual	38,702		38,702
90	242 - Misc Current & Accrued Liab			
91	254 - Ohio Reliability			
92	401 - Operation Expense - Nonassociated			
93	402 - Maintenance Exp			
94	407 - Regulatory Debits			
95	417 - Misc Exp	10,383,812		10,383,812
96	426 - Political Activities	51,919		51,919
95	TOTAL Other Accounts	26,497,931	(11,096,658)	15,401,273
96	TOTAL SALARIES AND WAGES	268,896,138		268,896,138

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Electric Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to the order of the Commission or other authorization.

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)	10,380,490	34,669,568	61,698,824	60,845,513
2.1	Net Purchases (Account 555.1)				
3	Net Sales (Account 447)	(39,399,554)	(53,761,843)	(78,028,517)	(134,336,912)
4	Transmission Rights	(2,175,606)	(7,013,537)	(11,573,066)	(12,546,614)
5	Ancillary Services	3,391,979	6,866,148	9,896,994	12,524,523
6	Other Items (list separately)				
7	Congestion	6,214,052	11,517,257	15,024,517	17,177,527
8	Operating Reserves	1,174,774	2,783,389	3,300,855	3,846,382
9	Transmission Purchase Expense	12,595,676	24,881,642	37,653,251	49,647,659
10	Transmission Losses	3,195,986	3,491,189	6,286,239	10,216,182
11	Meter Corrections	846	(12,340)	7,583	(744,367)
12	Inadvertent	13,015	89,548	236,892	230,407
13	Capacity Credits	(29,152)	(48,694)	491,205	898,276
46	TOTAL	(4,637,494)	23,462,327	44,994,777	7,758,576

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.
In columns for usage, report usage-related billing determinant and the unit of measure.

1. On Line 1 columns (b), (c), (d), and (e) report the amount of ancillary services purchased and sold during the year.
2. On Line 2 columns (b), (c), (d), and (e) report the amount of reactive supply and voltage control services purchased and sold during the year.
3. On Line 3 columns (b), (c), (d), and (e) report the amount of regulation and frequency response services purchased and sold during the year.
4. On Line 4 columns (b), (c), (d), and (e) report the amount of energy imbalance services purchased and sold during the year.
5. On Lines 5 and 6, columns (b), (c), (d), and (e) report the amount of operating reserve spinning and supplement services purchased and sold during the period.
6. On Line 7 columns (b), (c), (d), and (e) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollar (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	(a)0					
2	Reactive Supply and Voltage						
3	Regulation and Frequency Response						
4	Energy Imbalance						
5	Operating Reserve - Spinning						
6	Operating Reserve - Supplement						
7	Other						
8	Total (Lines 1 thru 7)						

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: AncillaryServicesPurchasedNumberOfUnits

The final grandfathered contracts (under the AEP OATT) expired 12/31/2010. Currently, services are provided under the SPP and PJM OATTs.

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

1. Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
2. Report on Column (b) by month the transmission system's peak load.
3. Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
4. Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
	NAME OF SYSTEM: 0									
1	January	(a)0								
2	February									
3	March									
4	Total for Quarter 1				0	0	0	0	0	0
5	April									
6	May									
7	June									
8	Total for Quarter 2				0	0	0	0	0	0
9	July									
10	August									
11	September									
12	Total for Quarter 3				0	0	0	0	0	0
13	October									
14	November									
15	December									
16	Total for Quarter 4				0	0	0	0	0	0
17	Total				0	0	0	0	0	0

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: MonthlyPeakLoadExcludingIsoAndRto
Indiana Michigan Power Company's transmission service is administered through an RTO/ISO and requested information is not available on an individual operating company basis.

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

Monthly ISO/RTO Transmission System Peak Load

1. Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
2. Report on Column (b) by month the transmission system's peak load.
3. Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
4. Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
5. Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Import into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (j)
	NAME OF SYSTEM: 0									
1	January									
2	February									
3	March									
4	Total for Quarter 1				0	0	0	0	0	0
5	April									
6	May									
7	June									
8	Total for Quarter 2				0	0	0	0	0	0
9	July									
10	August									
11	September									
12	Total for Quarter 3				0	0	0	0	0	0
13	October									
14	November									
15	December									
16	Total for Quarter 4				0	0	0	0	0	0
17	Total Year to Date/Year				0	0	0	0	0	0

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 2025-04-08	Year/Period of Report End of: 2024/ Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	17,920,217
3	Steam	[a]1,476,405	23	Requirements Sales for Resale (See instruction 4, page 311.)	2,765,933
4	Nuclear	18,028,412	24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	4,198,497
5	Hydro-Conventional	94,481	25	Energy Furnished Without Charge	49
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
7	Other	60,927	27	Total Energy Losses	1,203,185
8	Less Energy for Pumping		27.1	Total Energy Stored	
9	Net Generation (Enter Total of lines 3 through 8)	19,660,225	28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	26,087,881
10	Purchases (other than for Energy Storage)	6,427,656			
10.1	Purchases for Energy Storage	0			
11	Power Exchanges:				
12	Received	0			
13	Delivered	0			
14	Net Exchanges (Line 12 minus line 13)	0			
15	Transmission For Other (Wheeling)				
16	Received				
17	Delivered				
18	Net Transmission for Other (Line 16 minus line 17)	0			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of Lines 9, 10, 10.1, 14, 18 and 19)	26,087,881			

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 2025-04-08	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: SteamGeneration

Indiana Michigan Power Company purchased a 50% share of Rockport Unit 2 on December 8, 2022 and is operating as a merchant facility. Merchant operations volumes that are generated, purchased, and sold are not part of the volumes recorded on this page. Generated volumes were 1,047,499 for 2024, purchased volumes were 1,047,499 for 2024 and volumes sold to the market were 2,094,998 for 2024 .

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirement Sales for Resale & Associated Losses (c)	Monthly Peak - Megawatts (d)	Monthly Peak - Day of Month (e)	Monthly Peak - Hour (f)
	NAME OF SYSTEM: 0					
29	January	2,458,691	459,190	(a)(b)3,455	17	8
30	February	2,237,031	505,530	3,019	20	8
31	March	1,936,601	247,381	2,968	19	8
32	April	1,673,051	(44,104)	2,884	3	12
33	May	1,942,128	177,151	3,498	21	18
34	June	2,259,800	400,333	3,857	20	15
35	July	2,440,973	452,857	3,639	30	17
36	August	2,194,592	172,561	3,924	27	16
37	September	1,921,632	107,659	3,377	19	18
38	October	1,918,980	244,847	2,855	1	15
39	November	2,502,893	872,570	2,966	21	14
40	December	2,601,509	710,256	3,217	12	9
41	Total	26,087,881	4,306,231			

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: MonthlyPeakLoad

Indiana Jurisdictional Split of Peak Volumes

Month	Volume
Jan	2,954
Feb	2,589
Mar	2,544
Apr	2,470
May	2,985
Jun	3,241
Jul	3,058
Aug	3,279
Sep	2,856
Oct	2,471
Nov	2,520
Dec	2,747

Michigan Jurisdictional Split of Peak Volumes

Month	Volume
Jan	501
Feb	430
Mar	424
Apr	415
May	513
Jun	616
Jul	581
Aug	645
Sep	522
Oct	384
Nov	446
Dec	470

(b) Concept: MonthlyPeakLoad

Jurisdictional Split of Peak Volumes

Month	Volume

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

Steam Electric Generating Plant Statistics

1. Report data for plant in Service only.
2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants.
3. Indicate by a footnote any plant leased or operated as a joint facility.
4. If net peak demand for 60 minutes is not available, give data which is available, specifying period.
5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant.
6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mcf.
7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20.
8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.
9. Items under Cost of Plant are based on USofA accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses.
10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants.
11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant.
12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Line No.	Item (a)	Plant Name: Donald C Cook Plant	Plant Name: ROCKPORT TOTAL I&M	Plant Name: ROCKPORT TOTAL PLANT	Plant Name: ROCKPORT UNIT 1 I&M	Plant Name: ROCKPORT UNIT 2 I&M
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Nuclear	Steam	Steam [a]	Steam	Steam
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional	Conventional	Conventional	Conventional	Conventional
3	Year Originally Constructed	1975	1984	1984	1984	1989
4	Year Last Unit was Installed	1978	1989	1989	1984	1989
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	2,255	1,310	2,620	660	650
6	Net Peak Demand on Plant - MW (60 minutes)	2,314	1,310	2,620	660	650
7	Plant Hours Connected to Load	8,784	4,505	4,505	3,952	2,959
8	Net Continuous Plant Capability (Megawatts)	0	0	0	0	0
9	When Not Limited by Condenser Water	2,296	1,310	2,620	660	650
10	When Limited by Condenser Water	2,181	1,309	2,619	659	650
11	Average Number of Employees	964	0	149	0	0
12	Net Generation, Exclusive of Plant Use - kWh	18,028,412,000	2,531,018,000	5,062,036,000	1,476,405,000	1,054,613,000
13	Cost of Plant: Land and Land Rights	1,879,588	6,538,036	13,046,747	6,470,266	67,770
14	Structures and Improvements	479,217,675	116,092,210	309,735,759	87,585,922	28,506,288
15	Equipment Costs	3,200,209,098	1,130,311,351	2,797,614,189	818,281,303	312,030,048
16	Asset Retirement Costs	320,933,689	25,434,118	50,844,964	12,717,059	12,717,059
17	Total cost (total 13 thru 20)	4,002,240,050	1,278,375,715	3,171,241,659	925,054,550	353,321,165
18	Cost per KW of Installed Capacity (line 17/5) Including	1,774.8293	975.8593	1,210.3976	1,401.5978	543.5710
19	Production Expenses: Oper, Supv, & Engr	22,203,816	4,009,868	7,198,123	2,408,481	1,601,387
20	Fuel	108,260,991	88,594,970	177,196,027	49,624,544	38,970,426
21	Coolants and Water (Nuclear Plants Only)	9,932,181				
22	Steam Expenses	11,972,646	23,635,478	39,645,512	16,397,416	7,238,062
23	Steam From Other Sources					
24	Steam Transferred (Cr)					
25	Electric Expenses	5,329,268	1,387,687	2,398,613	873,399	514,288
26	Misc Steam (or Nuclear) Power Expenses	65,730,175	5,395,328	9,043,931	2,606,618	2,788,710
27	Rents		16,098	17,702	15,296	802
28	Allowances		4,354,525	4,354,525	3,626,223	728,302
29	Maintenance Supervision and Engineering	5,104,817	1,034,550	2,490,540	688,839	345,711
30	Maintenance of Structures	5,121,256	2,668,000	3,489,477	517,848	2,150,152
31	Maintenance of Boiler (or reactor) Plant	87,850,412	3,812,061	8,928,275	3,015,738	796,323
32	Maintenance of Electric Plant	15,999,419	1,656,593	3,779,378	1,320,481	336,112
33	Maintenance of Misc Steam (or Nuclear) Plant	22,605,800	445,991	1,143,827	359,736	86,255
34	Total Production Expenses	360,110,781	137,011,149	259,685,930	81,454,619	55,556,530
35	Expenses per Net kWh	0.0200	0.0541	0.0513	0.0552	0.0527

35	**Plant Name**	Donald C Cook Plant	ROCKPORT TOTAL I&M	ROCKPORT TOTAL I&M	ROCKPORT TOTAL PLANT	ROCKPORT TOTAL PLANT
36	Fuel Kind	Nuclear	Coal	Oil	Coal	Oil
37	Fuel Unit		t	bbl	t	bbl
38	Quantity (Units) of Fuel Burned		1,459,505	27,776	2,919,009	55,551
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)		8,602	137,915	8,602	137,915
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year		51.302	100.509	51.302	100.509
41	Average Cost of Fuel per Unit Burned		52.409	114.279	52.409	114.279
42	Average Cost of Fuel Burned per Million BTU	0.572	3.046	20	3.046	20
43	Average Cost of Fuel Burned per kWh Net Gen	0.006	0.030		0.030	
44	Average BTU per kWh Net Generation	10,496	9,944		9,944	

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: PlantKind

The Rockport Plant is a two unit coal fired generating facility. Units 1 and 2 are jointly owned by the Respondent and AEP Generating Company. Column (b) represents Respondent's 50% share of Unit 1 and column (c) represents Respondent's 50% share of Unit 2. Column (d) represents Respondent's total share of Rockport Plant and column (e) represents Total Rockport owned by Respondent and AEP Generating Company.

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

Hydroelectric Generating Plant Statistics

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings).
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: 0
1	Kind of Plant (Run-of-River or Storage)	
2	Plant Construction type (Conventional or Outdoor)	
3	Year Originally Constructed	
4	Year Last Unit was Installed	
5	Total installed cap (Gen name plate Rating in MW)	
6	Net Peak Demand on Plant-Megawatts (60 minutes)	
7	Plant Hours Connect to Load	
8	**Net Plant Capability (in megawatts)**	
9	(a) Under Most Favorable Oper Conditions	
10	(b) Under the Most Adverse Oper Conditions	
11	Average Number of Employees	
12	Net Generation, Exclusive of Plant Use - kWh	
13	**Cost of Plant**	
14	Land and Land Rights	
15	Structures and Improvements	
16	Reservoirs, Dams, and Waterways	
17	Equipment Costs	
18	Roads, Railroads, and Bridges	
19	Asset Retirement Costs	
20	Total cost (total 13 thru 20)	
21	Cost per KW of Installed Capacity (line 20 / 5)	
22	**Production Expenses**	
23	Operation Supervision and Engineering	
24	Water for Power	
25	Hydraulic Expenses	
26	Electric Expenses	
27	Misc Hydraulic Power Generation Expenses	
28	Rents	
29	Maintenance Supervision and Engineering	
30	Maintenance of Structures	
31	Maintenance of Reservoirs, Dams, and Waterways	
32	Maintenance of Electric Plant	
33	Maintenance of Misc Hydraulic Plant	
34	Total Production Expenses (total 23 thru 33)	
35	Expenses per net kWh	

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

Pumped Storage Generating Plant Statistics

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings).
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give that which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on Line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: 0
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	0
6	Plant Hours Connect to Load While Generating	0
7	Net Plant Capability (in megawatts)	0
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - kWh	0
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	0
12	**Cost of Plant**	
13	Land and Land Rights	
14	Structures and Improvements	0
15	Reservoirs, Dams, and Waterways	0
16	Water Wheels, Turbines, and Generators	0
17	Accessory Electric Equipment	0
18	Miscellaneous Powerplant Equipment	0
19	Roads, Railroads, and Bridges	0
20	Asset Retirement Costs	0
21	Total cost (total 13 thru 20)	
22	Cost per KW of installed cap (line 21 / 4)	
23	**Production Expenses**	
24	Operation Supervision and Engineering	0
25	Water for Power	0
26	Pumped Storage Expenses	0
27	Electric Expenses	0
28	Misc Pumped Storage Power generation Expenses	0
29	Rents	0
30	Maintenance Supervision and Engineering	0
31	Maintenance of Structures	0
32	Maintenance of Reservoirs, Dams, and Waterways	0
33	Maintenance of Electric Plant	0
34	Maintenance of Misc Pumped Storage Plant	0
35	Production Exp Before Pumping Exp (24 thru 34)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per kWh (line 37 / 9)	
39	Expenses per KWh of Generation and Pumping (line 37/(line 9 + line 10))	0

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating).
2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.
3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 402.
4. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (MW) (c)	Net Peak Demand MW (60 min) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)	Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses		Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Generation Type (m)
									Fuel Production Expenses (i)	Maintenance Production Expenses (j)			
1	Berrien Springs	1908	7.20	5.4	32,932	17,541,619	2,436,336	338,732		233,219			Hydro
2	Buchanan	1919	4.10	2.5	15,237	8,529,126	2,080,275	234,342		240,886			Hydro
3	Constantine	1921	1.20	0.9	3,513	4,494,108	3,745,090	154,811		203,990			Hydro
4	Elkhart	1913	3.44	2.4	13,009	10,722,200	3,116,919	189,050		239,000			Hydro
5	Mottville	1923	1.68	1.4	6,874	5,995,471	3,568,733	147,826		134,095			Hydro
6	Twin Branch	1904	4.80	3.7	22,916	15,328,839	3,193,508	363,717		1,831,027			Hydro
7	Deer Creek	2015	2.50	2.7	3,625	6,492,288	2,596,915	1,505		16,238			Solar
8	Olive	2016	5.00	5.5	8,637	12,087,538	2,417,508	3,009		37,034			Solar
9	St. Joseph	2020	20.00	22.3	37,999	38,261,077	1,913,054	65,870		141,430			Solar
10	Twin Branch Solar	2016	2.60	2.8	4,032	7,036,796	2,706,460	1,565		37,676			Solar
11	Watervliet	2016	4.60	4.9	6,634	12,005,987	2,609,997	2,768		44,356			Solar

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

ENERGY STORAGE OPERATIONS (Large Plants)

1. Large Plants are plants of 10,000 Kw or more.
2. In columns (a) (b) and (c) report the name of the energy storage project, functional classification (Production, Transmission, Distribution), and location.
3. In column (d), report Megawatt hours (MWH) purchased, generated, or received in exchange transactions for storage.
4. In columns (e), (f) and (g) report MWHs delivered to the grid to support production, transmission and distribution. The amount reported in column (d) should include MWHs delivered/provided to a generator's own load requirements or used for the provision of ancillary services.
5. In columns (h), (i), and (j) report MWHs lost during conversion, storage and discharge of energy.
6. In column (k) report the MWHs sold.
7. In column (l), report revenues from energy storage operations. In a footnote, disclose the revenue accounts and revenue amounts related to the income generating activity.
8. In column (m), report the cost of power purchased for storage operations and reported in Account 555.1, Power Purchased for Storage Operations. If power was purchased from an affiliated seller specify how the cost of the power was determined. In columns (n) and (o), report fuel costs for storage operations associated with self-generated power included in Account 501 and other costs associated with self-generated power.
9. In columns (q), (r) and (s) report the total project plant costs including but not exclusive of land and land rights, structures and improvements, energy storage equipment, turbines, compressors, generators, switching and conversion equipment, lines and equipment whose primary purpose is to integrate or tie energy storage assets into the power grid, and any other costs associated with the energy storage project included in the property accounts listed.

Line No.	Name of the Energy Storage Project (a)	Functional Classification (b)	Location of the Project (c)	MWHs (d)	MWHs delivered to the grid to support Production (e)	MWHs delivered to the grid to support Transmission (f)	MWHs delivered to the grid to support Distribution (g)	MWHs Lost During Conversion, Storage and Discharge of Energy Production (h)	MWHs Lost During Conversion, Storage and Discharge of Energy Transmission (i)	MWHs Lost During Conversion, Storage and Discharge of Energy Distribution (j)	MWHs Sold (k)	Revenues from Energy Storage Operations (l)	Power Purchased for Storage Operations (555.1) (Dollars) (m)	Fuel Costs from associated fuel accounts for Storage Operations Associated with Self-Generated Power (Dollars) (n)	Othe Cost Associ with S Genera Powe (Dolla (o)
1															
2															
35	TOTAL			0	0	0	0	0	0	0	0	0	0	0	

Line No.	Production (Dollars) (q)	Transmission (Dollars) (r)	Distribution (Dollars) (s)
1			
2			
35	0	0	0

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

ENERGY STORAGE OPERATIONS (Small Plants)

1. Small Plants are plants less than 10,000 Kw.
2. In columns (a), (b) and (c) report the name of the energy storage project, functional classification (Production, Transmission, Distribution), and location.
3. In column (d), report project plant cost including but not exclusive of land and land rights, structures and improvements, energy storage equipment and any other costs associated with the energy storage project.
4. In column (e), report operation expenses excluding fuel, (f), maintenance expenses, (g) fuel costs for storage operations and (h) cost of power purchased for storage operations and reported in Account 555.1, Power Purchased for Storage Operations. If power was purchased from an affiliated seller specify how the cost of the power was determined.
5. If any other expenses, report in column (i) and footnote the nature of the item(s).

Line No.	Name of the Energy Storage Project (a)	Functional Classification (b)	Location of the Project (c)	Project Cost (d)	BALANCE AT BEGINNING OF YEAR				
					Operations (Excluding Fuel used in Storage Operations) (e)	Maintenance (f)	Cost of fuel used in storage operations (g)	Account No. 555.1, Power Purchased for Storage Operations (h)	Other Expenses (i)
1	East Busco Substation	Distribution	East Busco	106,915	0	0	0	0	
2	TOTAL			106,915	0	0	0	0	0
36	TOTAL								

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage. If required by a State commission to report individual lines for all voltages, do so but do not group totals for each voltage under 132 kilovolts.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
4. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
5. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.
6. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g).
7. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
8. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
9. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Line No.	DESIGNATION		VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) - (In the case of underground lines report circuit miles)		Number of Circuits	Size of Conductor and Material	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)		
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line			Land	Construction Costs	Total Costs
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	STATE OF INDIANA	STATE OF INDIANA										
2	6128 DUMONT	JEFFERSON	765.00	765.00	3	202.50	0	1	4-954 KCM			
3	6136 DUMONT	WILTON CENTER	765.00	765.00	3	63.00	0	1	4-954 KCM			
4	6141 DUMONT	MARYSVILLE	765.00	765.00	3	99.38	0	1	4-954 KCM			
5	6215 D.C. COOK	DUMONT	765.00	765.00	3	20.00	0	1	4-954 KCM			
6	6223 ROCKPORT	JEFFERSON	765.00	765.00	3	111.00	0	1	4-1351 KCM			
7	6224 ROCKPORT	SULLIVAN	765.00	765.00	3	97.00	0	1	4-1351 KCM			
8	6226 JEFFERSON	WEST	765.00	765.00		0.00	0	0				
9	6236 HANGING ROCK	JEFFERSON	765.00	765.00	3	1.00	0	1	4-1351 KCM			
10	0675 TANNERS CREEK	SORENSON	345.00	345.00	3	135.58	0	2	1275 KCM			
11	0675 TANNERS CREEK	SORENSON	345.00	345.00	1	0.42	0	2	1414 KCM			
12	0676 SORENSON	EAST LIMA	345.00	345.00	3	29.68	0	1	1275 KCM			
13	0676 SORENSON	EAST LIMA	345.00	345.00	1	0.27	0	1	2-954 KCM			
14	0677 BREED	DEQUINE EAST	345.00	345.00	3	46.44	0	2	1414 KCM			
15	0677 BREED	DEQUINE EAST	345.00	345.00	3	45.13	0	1	1414 KCM			
16	0677 BREED	DEQUINE EAST	345.00	345.00	3	0.65	0	2	2-954 KCM			
17	0677 BREED	DEQUINE EAST	345.00	345.00	1	0.18	0	2	1414 KCM			
18	0677 BREED	DEQUINE EAST	345.00	345.00	1	3.77	0	2	2303 KCM			
19	0677 BREED	DEQUINE EAST	345.00	345.00	1	0.08	0	2	2-2303 KCM			
20	0678 DEQUINE	OLIVE	345.00	345.00	3	13.31	0	2	2303 KCM			
21	0678 DEQUINE	OLIVE	345.00	345.00	3	54.19	0	2	1,414KCM			
22	0678 DEQUINE	OLIVE	345.00	345.00	1	0.67	0	2	2156 KCM			
23	0678 DEQUINE	OLIVE	345.00	345.00	1	0.14	0	2	2,303 KCM			
24	0678 DEQUINE	OLIVE	345.00	345.00	1	0.45	0	2	2-954 KCM			
25	0679 SORENSON	OLIVE	345.00	345.00	3	77.90	0	1	1272 KCM			
26	0679 SORENSON	OLIVE	345.00	345.00	1	0.10	0	1	1272 KCM			
27	0680 OLIVE	GOODINGS GROVE	345.00	345.00	3	41.00	0	2	1414 KCM			
28	0683 DESOTO	JCT TOWER (MAR. CO)	345.00	345.00	3	53.00	6	1	2-954 KCM			
29	0684 TANNERS CREEK	JUNCTION TOWER	345.00	345.00	3	79.98	0	1	2-954 KCM			
30	0684 TANNERS CREEK	JUNCTION TOWER	345.00	345.00	2	0.02	0	1	2-954 KCM			
31	0685 HANNA	JUNCTION TOWER	345.00	345.00	3	5.63	0	0	2-954 KCM			
32	0687 TANNERS CREEK	MIAMI FORT	345.00	345.00	3	0.28	0	2	2-954 KCM			
33	0688 EUGENE	SIDNEY	345.00	345.00	1	0.20	0	1	1414 KCM			
34	0689 SORENSON-OLIVE	TWIN BRANCH	345.00	345.00	3	11.00	0	2	1563 KCM			
35	0690 BREED	CIPSCO	345.00	345.00	3	0.94	0	1	2-1024 KCM			
36	0690 BREED	CIPSCO	345.00	345.00	3	0.02	0	1	2-1351.5 KCM			
37	0691 BREED	PETERSBURG	345.00	345.00	3	0.70	0	1	2-954 KCM			
38	0691 BREED	PETERSBURG	345.00	345.00	1	0.15	0	1	2-1351.5 KCM			
39	0731 Varner	South Butler	345.00	345.00	1	0.60	0	1	2-954 KCM			
40	0734 Dunton Lake Extension		345.00	345.00	3	0.25	0	2	2-954 KCM			
41	6118 ROBISON PARK	SORENSON-EAST LIMA	345.00	345.00	3	22.66	0	2	1414 KCM			
42	6118 ROBISON PARK	SORENSON-EAST LIMA	345.00	345.00	1	0.34	0	1	1414 KCM			

Line No.	DESIGNATION		VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) - (In the case of underground lines report circuit miles)		Number of Circuits	Size of Conductor and Material	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)		
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line			Land	Construction Costs	Total Costs
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
43	6119 COOK	OLIVE	345.00	345.00	3	4.00	0	2	2-954 KCM			
44	6122 DUMONT	OLIVE	345.00	345.00	3	14.52	0	2	2-954 KCM			
45	6122 DUMONT	OLIVE	345.00	345.00	1	0.60	0	1	2-954 KCM			
46	6123 DUMONT	TWIN BRANCH	345.00	345.00	3	17.00	0	2	2-954 KCM			
47	6125 ROBISON PARK	EAST	345.00	345.00		0.00	0	0				
48	6133 DUMONT	BABCOCK	345.00	345.00	3	9.00	0	1	2-954 KCM			
49	6145 TWIN BRANCH	COOK-ROB PARK JCT	345.00	345.00	3	6.00	0	2	2-954 KCM			
50	6147 COOK	ROBISON PARK	345.00	345.00	3	67.41	0	2	2-954 KCM			
51	6147 COOK	ROBISON PARK	345.00	345.00	1	0.41	0	0	2-954 KCM			
52	6148 JACKSON ROAD	SORENSON-OLIVE	345.00	345.00	3	4.00	0	2	2303 KCM			
53	6213 COOK-ROB-PARK JCT	ARGENTA	345.00	345.00	3	2.00	0	2	2-954 KCM			
54	6237 JACKSON ROAD	WEST	345.00	345.00		0.00	0	0				
55	6240 TWIN BRANCH	SUBSTATION CORRIDOR	345.00	345.00		0.00	0	0				
56	6256 BREED	SULLIVAN	345.00	345.00	3	0.48	0	2	1351.5 KCM			
57	6256 BREED	SULLIVAN	345.00	345.00	3	0.75	0	1	1351.5 KCM			
58	6256 BREED	SULLIVAN	345.00	345.00	1	0.29	0	1	1351.5 KCM			
59	6259 COLLINGWOOD	SOUTH BUTLER	345.00	345.00	1	14.65	0	1	2-954 KCM			
60	6232 Arnold Hogan	Kenmore	34.00	138.00	1	1.26	0	2	795 KCM			
61	0604 TWIN BRANCH	ROBISON PARK	138.00	138.00	3	8.50	0	2	397.5 KCM			
62	0604 TWIN BRANCH	ROBISON PARK	138.00	138.00	1	0.28	0	2	1233.6 KCM			
63	0605 SOUTH BEND	MICHIGAN CITY	138.00	138.00	3	0.00	0	1	397.5 KCM			
64	0606 ROBISON PARK	HAVILAND	138.00	138.00	3	0.00	0	2	397.5 KCM			
65	0606 ROBISON PARK	HAVILAND	138.00	138.00	1	0.00	0	0	1233.6 KCM			
66	0607 ROBISON PARK	DEER CREEK	138.00	138.00	1	0.12	0	2	1590 KCM			
67	0607 ROBISON PARK	DEER CREEK	69.00	138.00	1	0.00	1	1	1033.5 KCM			
68	0608 DEER CREEK	KOKOMO	138.00	138.00	3	0.00	0	1	336.4 KCM			
69	0608 DEER CREEK	KOKOMO	138.00	138.00	3	1.88	0	1	636 KCM			
70	0608 DEER CREEK	KOKOMO	138.00	138.00	1	0.00	0	1	336.4 KCM			
71	0609 CONCORD TAP		138.00	138.00	3	4.00	0	2	397.5 KCM			
72	0613 TWIN BRANCH	JACKSON ROAD	138.00	138.00	3	8.00	0	2	447 KCM			
73	0614 LINCOLN TAP		138.00	138.00	3	4.00	0	2	397.5 KCM			
74	0615 TWIN BRANCH	ROBISON PARK	138.00	138.00	3	65.83	0	1	477 KCM			
75	0616 DEER CREEK	DELAWARE	138.00	138.00	3	2.40	0	2	397.5 KCM			
76	0618 DELAWARE	COLLEGE CORNER	138.00	138.00	3	48.81	0	2	397.5 KCM			
77	0618 DELAWARE	COLLEGE CORNER	138.00	138.00	4	0.84	0	2	2,000KCM			
78	0618 DELAWARE	COLLEGE CORNER	138.00	138.00	2	0.11	0	2	397.5 KCM			
79	0618 DELAWARE	COLLEGE CORNER	138.00	138.00	1	0.75	0	2	397.5 KCM			

Line No.	DESIGNATION		VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) - (In the case of underground lines report circuit miles)		Number of Circuits	Size of Conductor and Material	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)		
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line			Land	Construction Costs	Total Costs
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
80	0618 DELAWARE	COLLEGE CORNER	138.00	138.00	1	0.20	0	2	556.5 KCM			
81	0618 DELAWARE	COLLEGE CORNER	138.00	138.00	2	1.02	0	1	795 KCM			
82	0619 MADISON	NEW CASTLE	138.00	138.00	3	6.00	1	1	795 KCM			
83	0620 TANNERS CREEK	MADISON	138.00	138.00	3	82.00	0	2	636 KCM			
84	0620 TANNERS CREEK	MADISON	138.00	138.00	1	0.15	0	1	795 KCM			
85	0622 JACKSON ROAD	OLIVE	138.00	138.00	3	16.09	1	1	556.5 KCM			
86	0622 JACKSON ROAD	OLIVE	138.00	138.00	1	0.67	0	1	556.5 KCM			
87	0623 MADISON	PENDLETON	138.00	138.00	2	5.00	0	1	477 KCM			
88	0624 DRAGOON TAP		138.00	138.00	3	2.00	0	1	795 KCM			
89	0625 TANNERS CREEK	COLLEGE CORNER	138.00	138.00	3	51.90	0	2	636 KCM			
90	0625 TANNERS CREEK	COLLEGE CORNER	138.00	138.00	1	0.37	0	2	636 KCM			
91	0626 COLLEGE CORNER	RANDOLPH	138.00	138.00	2	34.58	0	1	556.5 KCM			
92	0626 COLLEGE CORNER	RANDOLPH	138.00	138.00	1	1.07	0	1	556.5 KCM			
93	0626 COLLEGE CORNER	RANDOLPH	138.00	138.00	2	3.34	0	0	556.5 KCM			
94	0627 RANDOLPH	JAY	138.00	138.00	2	0.00	0	1	556.5 KCM			
95	0627 RANDOLPH	JAY	138.00	138.00	1	0.32	0	0	556.5 KCM			
96	0628 MCKINLEY TAP		138.00	138.00	3	0.85	0	2	300 KCM CU			
97	0628 MCKINLEY TAP		138.00	138.00	1	0.15	0	2	300 KCM CU			
98	0629 JAY	LINCOLN	138.00	138.00	2	0.00	0	1	556.5 KCM			
99	0629 JAY	LINCOLN	138.00	138.00	3	0.00	0	1	1033.5 KCM			
100	0630 NEW CARLISLE	MAPLE	138.00	138.00	2	1.00	0	1	397.5 KCM			
101	6104 SORENSON	TWIN BRANCH	138.00	138.00	3	61.13	0	1	447 KCM			
102	6104 SORENSON	TWIN BRANCH	138.00	138.00	1	3.62	0	1	556.5 KCM			
103	6104 SORENSON	TWIN BRANCH	138.00	138.00	1	0.03	0	1	795 KCM			
104	0632 SORENSON	DEVILS HOLLOW	138.00	138.00	3	0.00	0	0	556.5 KCM			
105	0634 Makahoy	Marion	138.00	138.00	2	0.30	0	1	556.5 KCM			
106	0635 PENDLETON	MULLIN	138.00	138.00	2	14.10	0	1	556.5 KCM			
107	0635 PENDLETON	MULLIN	138.00	138.00	3	0.40	0	1	556.5 KCM			
108	0635 PENDLETON	MULLIN	138.00	138.00	1	0.72	0	1	556.5 KCM			
109	0636 DEER CREEK	FISHER BODY	138.00	138.00	3	5.04	0	2	397.5 KCM			
110	0637 TWIN BRANCH	EAST ELKHART	138.00	138.00	3	17.00	1	2	556.5 KCM			
111	0638 GRANT	FISHER BODY	138.00	138.00	3	0.00	1	1	397.5 KCM			
112	0639 ROBISON PARK	AUBURN	138.00	138.00	1	0.00	0	1	556.5 KCM			
113	0641 DESOTO	MEDFORD	138.00	138.00	1	0.15	0	2	795 KCM			
114	0641 DESOTO	MEDFORD	138.00	138.00	3	6.86	0	2	556.5 KCM			
115	0642 OLIVE	HICKORY CREEK	138.00	138.00	3	2.99	2	1	556.5 KCM			
116	0645 COREY TAP		138.00	138.00	2	3.34	0	1	477 KCM			
117	0646 OLIVE	NEW CARLISLE	138.00	138.00	3	2.00	0	1	556.5 KCM			
118	0647 OLIVE	SOUTH BEND	138.00	138.00	3	15.97	0	2	397.5 KCM			

Line No.	DESIGNATION		VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) - (In the case of underground lines report circuit miles)		Number of Circuits	Size of Conductor and Material	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)		
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line			Land	Construction Costs	Total Costs
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
119	0648 MEDFORD TAP		138.00	138.00	1	0.13	0	2	556.5 KCM			
120	0648 MEDFORD TAP		138.00	138.00	3	7.94	0	2	556.5 KCM			
121	0723 SPY RUN STATION		138.00	138.00	4	0.00	0	1	3.5IN OD			
122	0730 Varner	Wilmington	138.00	138.00	1	0.83	0	1	795 KCM			
123	0742 Deptmer Sw	Harber (REMC)	69.00	138.00	1	0.06	0	1	795 KCM			
124	6101 WESTINGHOUSE TAP		138.00	138.00	3	2.00	0	2	556.5 KCM			
125	6102 MILAN TAP		138.00	138.00	3	6.00	0	2	397.5 KCM			
126	6103 MILAN	GOODRICH	138.00	138.00	3	1.00	0	2	397.5 KCM			
127	6105 DESOTO	JAY	138.00	138.00	2	10.31	0	1	2-556.5 KCM			
128	6105 DESOTO	JAY	138.00	138.00	3	2.25	0	1	2-556.5 KCM			
129	6106 DESOTO	DEER CREEK-DELAWARE	138.00	138.00	3	7.21	0	2	636 KCM			
130	6106 DESOTO	DEER CREEK-DELAWARE	138.00	138.00	1	1.20	0	0	636 KCM			
131	6107 DARDEN TAP		138.00	138.00	2	0.94	0	1	336.4 KCM			
132	6109 ROBISON PARK	RICHLAND	138.00	138.00	2	13.76	0	1	636 KCM			
133	6109 ROBISON PARK	RICHLAND	138.00	138.00	1	0.05	0	0	1233.6 KCM			
134	6109 ROBISON PARK	RICHLAND	138.00	138.00	3	4.49	0	0	636 KCM			
135	6110 WESTINGHOUSE	23RD STREET	138.00	138.00	3	0.00	0	2	556.5 KCM			
136	6111 KANKAKEE	WEST SIDE	138.00	138.00	1	2.00	0	1	636 KCM			
137	6113 INDUSTRIAL PARK		138.00	138.00	3	3.00	0	2	745 KCM			
138	6114 OLIVE	MICHIGAN CITY	138.00	138.00	3	1.94	1	1	636 KCM			
139	6115 HUMMEL CREEK	VAN BUREN	138.00	138.00	3	6.00	0	2	795 KCM			
140	6130 HUMMEL CREEK	TOWER 70, GREENTOWN	138.00	138.00		0.00	0	0				
141	6116 SOUTH ELWOOD TAP		138.00	138.00	1	3.07	0	1	556.5 KCM			
142	6117 PENDLETON	FALL CREEK	138.00	138.00	3	10.70	0	2	795 KCM			
143	6117 PENDLETON	FALL CREEK	138.00	138.00	1	0.07	0	2	795 KCM			
144	6121 ROBISON PARK	LINCOLN	138.00	138.00	3	0.03	0	1	795 KCM			
145	6121 ROBISON PARK	LINCOLN	138.00	138.00	1	0.02	0	0	1233.6 KCM			
146	6126 CONCORD	EAST ELKHART	138.00	138.00	3	11.00	0	1	795 KCM			
147	6129 GREENTOWN-GRANT	HUMMEL CREEK	138.00	138.00	3	21.00	0	1	795 KCM			
148	6131 INDUSTRIAL PARK	MC KINLEY	138.00	138.00	1	4.96	0	1	795 KCM			
149	6132 CROSS STREET TAP	JUNCTION TOWER #88	138.00	138.00	1	4.00	0	1	795 KCM			
150	6134 LINCOLN	ANTHONY	138.00	138.00	1	3.00	0	1	795 KCM			
151	6135 WAYNEDALE TAP		138.00	138.00	3	0.00	0	2	795 KCM			
152	6138 JACKSON ROAD	SOUTH SIDE	138.00	138.00	1	2.00	0	1	795 KCM			
153	6142 ALBION	KENDALLVILLE	138.00	138.00	3	10.00	0	1	795 KCM			
154	6150 SOUTHSIDE	SOUTH BEND	138.00	138.00	1	6.07	0	1	795 KCM			

Line No.	DESIGNATION		VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) - (In the case of underground lines report circuit miles)		Number of Circuits	Size of Conductor and Material	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)		
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line			Land	Construction Costs	Total Costs
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
155	6219 DELCO BATTERY TAP		138.00	138.00	1	0.94	0	2	795 KCM AA			
156	6220 FALL CREEK	MADISON-NEW CASTLE	138.00	138.00	3	1.10	0	2	795 KCM			
157	6220 FALL CREEK	MADISON-NEW CASTLE	138.00	138.00	1	0.15	0	2	795 KCM			
158	6225 INDUSTRIAL PARK	SPY RUN	138.00	138.00	1	4.10	0	1	1033 KCM			
159	6266 WALLEN		138.00	138.00	1	0.22	0	1	1033.5 KCM			
160	6234 CABOT TAP/CR 4	EAST ELKHART	138.00	138.00	1	0.13	0	1	556.5 KCM			
161	6238 SORENSON	MCKINLEYTOWER	138.00	138.00	3	2.82	0	2	795 KCM			
162	6238 SORENSON	MCKINLEYTOWER	138.00	138.00	1	0.26	0	2	795 KCM			
163	6241 KENDALLVILLE TAP	CITY OF AUBURN #5	138.00	138.00	1	14.00	0	1	795 KCM			
164	6241 KENDALLVILLE TAP	CITY OF AUBURN #5	138.00	138.00	2	14.00	0	1	795 KCM			
165	6242 AUBURN	CITY OF AUBURN #5	138.00	138.00	1	2.00	0	1	795 KCM			
166	6245 LAPORTE JCT	LIQUID CARBONICS	138.00	138.00	1	4.76	0	1	795 KCM			
167	6245 LAPORTE JCT	LIQUID CARBONICS	138.00	138.00	1	0.23	0	0	1033.5 KCM			
168	6246 LAPORTE JCT	AIRCO	138.00	138.00	1	0.72	0	1	795 KCM			
169	6248 ELCONA TAP	CONC-DUN-E-ELK	138.00	138.00	1	2.00	0	1	795 KCM			
170	6249 ALLEN	LINCOLN	138.00	138.00	3	4.90	0	2	1033 KCM			
171	6249 ALLEN	LINCOLN	138.00	138.00	1	0.09	0	2	1233.6 KCM			
172	6250 ALLEN	ADAMS/HILLCREST	138.00	138.00	3	4.92	0	2	1033 KCM			
173	6250 ALLEN	ADAMS/HILLCREST	138.00	138.00	1	0.07	0	2	1233.6 KCM			
174	6251 OLIVE	EDISON	138.00	138.00	3	1.00	0	2	795 KCM			
175	6253 TRIER RD TAP		138.00	138.00	1	0.00	0	1	795 KCM			
176	6258 KENZIE CREEK	TWIN BRANCH	138.00	138.00	3	0.00	0	2	1033 KCM			
177	6260 WILMINGTON TAP		138.00	138.00	1	0.20	9	1	2-954 KCM			
178	6229 DUNLAP NORTH TAP		34.00	138.00	1	2.00	0	2	795 KCM			
179	6140 INDIANA-PURDUE		34.00	138.00	1	0.00	0	2	1033 KCM			
180	6217 HILLCREST	KINNERK	69.00	138.00	1	3.92	0	1	795 KCM			
181	6217 HILLCREST	KINNERK	69.00	138.00	2	0.03	0	1	795 KCM			
182	6252 KENDALLVILLE	BIXLER	138.00	138.00	1	2.91	0	1	795 KCM			
183	6254 ALLEN/LINCOLN	ALLEN/HILLCREST	138.00	138.00		0.00	0	0				
184	6265 CONCORD	WOLF	138.00	138.00	1	0.77	0	1	336.4 KCM			
185	6271 INDALEX TAP/CR 4	EAST ELKHART	138.00	138.00	1	1.09	0	1	556.5 KCM			
186	6267 STUDEBAKER	WEST SIDE	138.00	138.00	1	2.57	0	1	954 KCM			
187	6270 JONES CREEK	HOGAN	138.00	138.00		5.47	0	1	795 KCM			
188	6273 DAWKINS SWITCH	HERBERT MONROE (WVPA)	138.00	138.00	1	0.50	0	1	4/0			
189	LINES<132 KV	SYSTEM	69.00	0.00	Various	488.16	72	1	VARIOUS			

Line No.	DESIGNATION		VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) - (In the case of underground lines report circuit miles)		Number of Circuits	Size of Conductor and Material	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)		
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line			Land	Construction Costs	Total Costs
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
190	STATE OF MICHIGAN	STATE OF MICHIGAN	0.00	0.00		0.00	0	0				
191	6216 D.C. COOK	DUMONT	765.00	765.00	3	16.00	0	1	4-954 KCM			
192	6120 COOK	PALISADES	345.00	345.00	3	41.78	0	2	2-954 KCM			
193	6120 COOK	PALISADES	345.00	345.00	1	0.23	0	0	2-954 KCM			
194	6120 COOK	PALISADES	345.00	345.00	1	0.21	0	0	2-1158.4 KCM			
195	6143 D.C. COOK	OLIVE-PALISADES	345.00	345.00	3	5.00	0	2	2-954 KCM			
196	6144 TWIN BRANCH	COOK-ROB PARK JCT	345.00	345.00	3	0.00	0	2	2-954 KCM			
197	6151 COOK	OLIVE	345.00	345.00		0.00	0	0				
198	6152 COOK	ROBISON PARK	345.00	345.00		0.00	0	0				
199	6146 D.C. COOK	ROBISON PARK	345.00	345.00	3	36.80	0	2	2-954 KCM			
200	6146 D.C. COOK	ROBISON PARK	345.00	345.00	3	0.09	0	0	954 KCM			
201	6214 COOK-ROB PARK	ARGENTA	345.00	345.00	3	28.78	0	2	2-954 KCM			
202	6214 COOK-ROB PARK	ARGENTA	345.00	345.00	1	0.22	0	2	2-954 KCM			
203	6221 D.C. COOK	OLIVE-PALISADES	345.00	345.00	3	5.00	0	2	2-954 KCM			
204	6263 BARODA TAP		138.00	138.00		0.00	0	0				
205	0601 TWIN BRANCH	RIVERSIDE	138.00	138.00	3	0.00	0	2	397.5KCM & 1033.5			
206	0601 TWIN BRANCH	RIVERSIDE	138.00	138.00	1	0.00	0	2	397.5KCM & 1033.5			
207	0610 AUTO SPECIALTIES		138.00	138.00		0.00	0	0				
208	0621 TWIN BRANCH - R	HICKORY CREEK	138.00	138.00	3	5.00	0	2	397.5 KCM			
209	0643 OLIVE	HICKORY CREEK	138.00	138.00	3	23.10	2	1	556.5 KCM			
210	0644 RIVERSIDE	HARTFORD	138.00	138.00	2	14.22	0	1	397.5 KCM			
211	0644 RIVERSIDE	HARTFORD	138.00	138.00	3	2.11	0	0	397.5 KCM			
212	0649 COREY TAP		138.00	138.00	2	12.12	0	1	477 KCM			
213	0649 COREY TAP		138.00	138.00	1	0.13	0	1	477 KCM			
214	6150 SOUTHSIDE	SOUTH BEND	138.00	138.00	1	6.23	0	1	795 KCM			
215	6108 RIVERSIDE	OLIVE-HICKORY CREEK	138.00	138.00	1	6.00	0	1	636 KCM			
216	6124 BENTON HARBOR	RIVERSIDE-HARTFORD	138.00	138.00	3	1.00	0	2	795 KCM			
217	6137 EDGEWATER TAP		138.00	138.00	1	0.76	0	1	556.5 KCM			
218	6149 HARTFORD	COREY	138.00	138.00	1	18.97	0	1	795 KCM			
219	6149 HARTFORD	COREY	138.00	138.00		0.00	2	1	795 KCM			
220	6149 HARTFORD	COREY	138.00	138.00	2	12.88	0	1	795 KCM			
221	6149 HARTFORD	COREY	138.00	138.00		0.00	1	1	1033.5 KCM			
222	6149 HARTFORD	COREY	138.00	138.00	1	1.34	0	1	1033.5 KCM			
223	6149 HARTFORD	COREY	138.00	138.00	1	0.53	0	2	1033.5 KCM			
224	6218 MOTTVILLE TAP		138.00	138.00	1	0.00	0	1	795 KCM			
225	6219 DELCO BATTERY TAP		138.00	138.00	1	0.50	0	2	795 KCM			
226	6219 DELCO BATTERY TAP		138.00	138.00	1	0.15	0	1	795 KCM			
227	6255 KENZIE CREEK	VALLEY	138.00	138.00	1	20.00	0	1	1033 KCM			
228	6257 KENZIE CREEK	T B/R'SIDE/HICK CR	138.00	138.00	3	0.00	0	0	795 KCM			

Line No.	DESIGNATION		VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) - (In the case of underground lines report circuit miles)		Number of Circuits	Size of Conductor and Material	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)		
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line			Land	Construction Costs	Total Costs
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
229	6261 FLATBUSH TAP		138.00	138.00		1.00	0	1				
230	6262 WEST ST TAP		138.00	138.00		1.00	0	2				
231	6700 GM HYDRAMATIC		138.00	138.00	3	2.00	0	2	795 KCM			
232	6227 NICKERSON	TOWER #13A	138.00	138.00		0.00	0	0				
233	6268 SAUK TRAIL		138.00	138.00	1	1.60	0	0	1033.5KCM 45/7ACR			
234	LESS THAN 132 KV LINES		69.00	0.00	Various	364.40	12	0	VARIOUS			
235	Line cost and expense are	not available by individual								84,422,117	845,070,010	929,492,126
236	transmission line.	Total shown in column j-p										
36	TOTAL					3,190	112	292		84,422,117	845,070,010	929,492,126

Line No.	EXPENSES, EXCEPT DEPRECIATION AND TAXES			
	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47				
48				
49				
50				
51				
52				

Line No.	EXPENSES, EXCEPT DEPRECIATION AND TAXES			
	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)
53				
54				
55				
56				
57				
58				
59				
60				
61				
62				
63				
64				
65				
66				
67				
68				
69				
70				
71				
72				
73				
74				
75				
76				
77				
78				
79				
80				
81				
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95				
96				
97				
98				
99				
100				
101				
102				
103				
104				

Line No.	EXPENSES, EXCEPT DEPRECIATION AND TAXES			
	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)
105				
106				
107				
108				
109				
110				
111				
112				
113				
114				
115				
116				
117				
118				
119				
120				
121				
122				
123				
124				
125				
126				
127				
128				
129				
130				
131				
132				
133				
134				
135				
136				
137				
138				
139				
140				
141				
142				
143				
144				
145				
146				
147				
148				
149				
150				
151				
152				
153				
154				
155				
156				

Line No.	EXPENSES, EXCEPT DEPRECIATION AND TAXES			
	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)
157				
158				
159				
160				
161				
162				
163				
164				
165				
166				
167				
168				
169				
170				
171				
172				
173				
174				
175				
176				
177				
178				
179				
180				
181				
182				
183				
184				
185				
186				
187				
188				
189				
190				
191				
192				
193				
194				
195				
196				
197				
198				
199				
200				
201				
202				
203				
204				
205				
206				
207				
208				

Line No.	EXPENSES, EXCEPT DEPRECIATION AND TAXES			
	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)
209				
210				
211				
212				
213				
214				
215				
216				
217				
218				
219				
220				
221				
222				
223				
224				
225				
226				
227				
228				
229				
230				
231				
232				
233				
234				
235	286,846	10,997,294		11,284,140
236				
36	286,846	10,997,294	0	11,284,140

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE		CONDUCTORS			Voltage KV (Operating)	LINE COST					Construction
	From	To		Type	Average Number per Miles	Present	Ultimate	Size	Specification	Configuration and Spacing		Land and Land Rights	Poles, Towers and Fixtures	Conductors and Devices	Asset Retire. Costs	Total	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
1	Nothing to Report																
44	TOTAL		0		0	0	0										

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).
5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Line No.	Name and Location of Substation (a)	Character of Substation		VOLTAGE (In MVa)			Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment		
		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVa) (c)	Secondary Voltage (In MVa) (d)	Tertiary Voltage (In MVa) (e)				Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
1	ADAMS (IM) - IN	Transmission		138.00	13.00	0.00	12.50	1	0		0	0.00
2	ADAMS (IM) - IN	Transmission		138.00	69.00	34.00	115.00	1	0		0	0.00
3	ALBION - IN	Transmission		69.00	0.00	0.00	0.00	0	0	STATCAP	1	14.40
4	ALBION - IN	Transmission		138.00	0.00	0.00	0.00	0	0	STATCAP	1	52.79
5	ALBION - IN	Transmission		69.00	12.00	0.00	8.40	1	0		0	0.00
6	ALBION - IN	Transmission		138.00	69.00	12.00	90.00	1	0		0	0.00
7	ALLEN (IM) - IN	Transmission		345.00	137.50	13.80	450.00	1	0		0	0.00
8	ANACONDA - IN	Distribution		34.50	4.00	0.00	3.75	1	0		0	0.00
9	ANCHOR HOCKING (IM) - IN	Distribution		69.00	13.09	0.00	20.00	1	0		0	0.00
10	ANCHOR HOCKING (IM) - IN	Distribution		69.00	2.40	0.00	13.75	2	0		0	0.00
11	ANTHONY - IN	Transmission		138.00	34.00	0.00	112.00	1	0		0	0.00
12	ANTHONY - IN	Transmission		34.50	12.00	0.00	29.38	2	0		0	0.00
13	ANTIVILLE - IN	Distribution		69.00	12.00	0.00	3.65	1	0		0	0.00
14	ARMSTRONG CORK - IN	Distribution		69.00	4.00	0.00	19.88	2	0		0	0.00
15	ARNOLD HOGAN - IN	Transmission		138.00	34.50	0.00	75.00	1	0		0	0.00
16	AUBURN - IN	Transmission		138.00	70.50	36.20	130.00	1	0		0	0.00
17	AUBURN - IN	Transmission		138.00	0.00	0.00	0.00	0	0	STATCAP	2	105.59
18	BEECH ROAD - IN	Distribution		138.00	13.09	0.00	20.00	1	0		0	0.00
19	BERNE - IN	Distribution		69.00	0.00	0.00	0.00	0	0	STATCAP	1	16.20
20	BERNE - IN	Distribution		69.00	12.00	0.00	20.00	1	0		0	0.00
21	BIG RUN - IN	Transmission		69.00	0.48	0.00	2.50	1	0		0	0.00
22	BIXLER - IN	Distribution		138.00	13.09	0.00	20.00	1	0		0	0.00
23	BLAINE STREET - IN	Distribution		34.50	13.00	0.00	20.00	1	0		0	0.00
24	BLUFF POINT - IN	Transmission		69.00	13.00	0.00	5.60	1	0		0	0.00
25	BLUFF POINT - IN	Transmission		69.00	0.00	0.00	0.00	0	0	STATCAP	1	16.20
26	BLUFFTON (IM) - IN	Transmission		69.00	0.00	0.00	0.00	0	0	STATCAP	1	16.20
27	BUTLER (IM) - IN	Distribution		69.00	13.00	0.00	20.00	1	0		0	0.00
28	BUTLER (IM) - IN	Distribution		69.00	0.00	0.00	0.00	0	0	STATCAP	2	30.00
29	CALVERT - IN	Distribution		138.00	13.09	0.00	20.00	1	0		0	0.00
30	CAPITAL AVENUE - IN	Transmission		138.00	13.09	0.00	12.00	1	0		0	0.00
31	CARROLL - IN	Distribution		34.50	13.00	0.00	1.50	3	0		0	0.00
32	CLEVELAND - IN	Distribution		138.00	13.09	0.00	12.00	1	0		0	0.00
33	Clipper - IN	Distribution		69.00	13.09	0.00	6.25	1	0		0	0.00
34	COLONY BAY - IN	Distribution		69.00	13.00	0.00	22.40	1	0		0	0.00
35	COLONY BAY - IN	Distribution		69.00	12.00	0.00	20.00	1	0		0	0.00
36	CONANT - IN	Distribution		34.50	12.00	0.00	22.40	1	0		0	0.00
37	CONCORD - IN	Transmission		138.00	70.50	36.20	130.00	1	0		0	0.00
38	CONCORD - IN	Transmission		138.00	13.09	0.00	22.40	1	0		0	0.00

Line No.	Name and Location of Substation (a)	Character of Substation		VOLTAGE (In MVa)			Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment		
		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVa) (c)	Secondary Voltage (In MVa) (d)	Tertiary Voltage (In MVa) (e)				Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
39	CONCORD - IN	Transmission		138.00	0.00	0.00	0.00	0	0	STATCAP	1	57.60
40	CONCORD - IN	Transmission		138.00	13.09	0.00	22.40	1	0		0	0.00
41	COUNTRYSIDE - IN	Distribution		138.00	12.47	0.00	20.00	1	0		0	0.00
42	COUNTY LINE (IM) - IN	Distribution		138.00	13.09	0.00	20.00	1	0		0	0.00
43	COUNTY ROAD 4 - IN	Distribution		138.00	13.09	0.00	20.00	1	0		0	0.00
44	CROSS STREET - IN	Distribution		138.00	13.09	0.00	20.00	1	0		0	0.00
45	DALEVILLE - IN	Distribution		138.00	13.09	0.00	20.00	1	0		0	0.00
46	DARDEN ROAD - IN	Distribution		138.00	13.09	0.00	42.40	2	0		0	0.00
47	DECATUR (FTW) - IN	Transmission		69.00	13.00	0.00	20.00	1	0		0	0.00
48	DECATUR (FTW) - IN	Transmission		69.00	0.00	0.00	0.00	0	0	XSLR - 0.4mH / 480A	3	0.00
49	DECATUR (FTW) - IN	Transmission		69.00	0.00	0.00	0.00	0	0	STATCAP	1	23.00
50	DEER CREEK - IN	Transmission		138.00	69.00	34.00	90.00	1	0		0	0.00
51	DEER CREEK - IN	Transmission		138.00	0.00	0.00	0.00	0	0	STATCAP	1	57.60
52	DEER CREEK - IN	Transmission		138.00	13.09	0.00	12.00	1	0		0	0.00
53	DEER CREEK - IN	Transmission		138.00	34.50	0.00	75.00	1	0		0	0.00
54	DEER CREEK - IN	Transmission		138.00	13.09	0.00	20.00	1	0		0	0.00
55	DELAWARE (IM) - IN	Transmission		138.00	0.00	0.00	0.00	0	0	STATCAP	2	52.79
56	DELAWARE (IM) - IN	Transmission		138.00	0.00	0.00	0.00	0	0	XSLR - 0.6mH / 480A	3	0.00
57	DELAWARE (IM) - IN	Transmission		138.00	34.00	0.00	125.00	2	0		0	0.00
58	DESOTO - IN	Transmission		345.00	138.00	34.50	675.00	1	0		0	0.00
59	DIEBOLD ROAD - IN	Distribution		69.00	13.00	0.00	20.00	1	0		0	0.00
60	DOOVILLE - IN	Distribution		138.00	13.09	0.00	12.00	1	0		0	0.00
61	DRAGOON - IN	Transmission		138.00	69.00	34.00	84.00	1	0		0	0.00
62	DUMONT - IN	Transmission		765.00	0.00	0.00	0.00	0	0	REACTOR	2	200.00
63	DUNLAP - IN	Transmission		138.00	13.09	0.00	20.00	1	0		0	0.00
64	EAST ELKHART - IN	Transmission		345.00	137.50	13.80	450.00	1	0		0	0.00
65	EAST SIDE (IM) - IN	Distribution		138.00	13.09	0.00	37.40	2	0		0	0.00
66	EGE - IN	Distribution		138.00	34.50	13.00	5.00	1	0		0	0.00
67	ELCONA - IN	Distribution		138.00	13.09	0.00	22.40	1	0		0	0.00
68	ELKHART HYDRO STAT - IN	Transmission		34.50	13.09	0.00	48.00	4	0		0	0.00
69	ELKHART HYDRO STAT - IN	Transmission		34.50	13.09	0.00	12.50	2	0		0	0.00
70	ELKHART HYDRO STAT - IN	Transmission		34.50	4.36	0.00	12.50	2	0		0	0.00
71	ELLISON ROAD - IN	Transmission		138.00	13.09	0.00	20.00	1	0		0	0.00
72	FARMLAND - IN	Distribution		69.00	13.09	0.00	20.00	1	0		0	0.00
73	FERGUSON - IN	Distribution		69.00	13.00	0.00	20.00	1	0		0	0.00
74	FISHER BODY - IN	Distribution		138.00	13.80	0.00	100.00	2	0		0	0.00
75	FULTON (IM) - IN	Distribution		34.50	13.09	0.00	12.00	1	0		0	0.00
76	GASTON - IN	Distribution		138.00	13.09	0.00	20.00	1	0		0	0.00
77	GATEWAY (IM) - IN	Transmission		69.00	0.00	0.00	0.00	0	0	STATCAP	1	13.19
78	GERMAN - IN	Distribution		138.00	13.09	0.00	47.40	2	0		0	0.00
79	GLENBROOK - IN	Distribution		34.50	13.09	0.00	12.00	1	0		0	0.00
80	GLENBROOK - IN	Distribution		34.50	13.00	0.00	20.00	1	0		0	0.00
81	GRABILL - IN	Distribution		138.00	13.09	0.00	20.00	1	0		0	0.00
82	GRANGER - IN	Distribution		138.00	12.47	0.00	20.00	1	0		0	0.00
83	GRANGER - IN	Distribution		138.00	13.09	0.00	20.00	1	0		0	0.00
84	GRANT - IN	Transmission		138.00	34.50	0.00	30.00	1	0		0	0.00
85	GRANT - IN	Transmission		138.00	13.09	0.00	20.00	1	0		0	0.00
86	GREENLEAF - IN	Distribution		34.50	13.09	0.00	20.00	1	0		0	0.00

Line No.	Name and Location of Substation (a)	Character of Substation		VOLTAGE (In MVa)			Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment		
		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVa) (c)	Secondary Voltage (In MVa) (d)	Tertiary Voltage (In MVa) (e)				Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
87	GREENTOWN - IN	Transmission		765.00	0.00	0.00	0.00	0	0	REACTOR	4	200.00
88	HACIENDA - IN	Distribution		138.00	13.09	0.00	45.00	2	0		0	0.00
89	HADLEY - IN	Distribution		69.00	13.00	0.00	40.00	2	0		0	0.00
90	HARLAN - IN	Distribution		69.00	13.09	0.00	12.50	1	0		0	0.00
91	HARPER - IN	Distribution		138.00	13.09	0.00	20.00	1	0		0	0.00
92	HARTFORD CITY - IN	Transmission		69.00	13.00	0.00	20.00	1	0		0	0.00
93	HARVEST PARK - IN	Distribution		34.50	13.00	0.00	20.00	1	0		0	0.00
94	HAYMOND - IN	Distribution		34.50	13.09	0.00	20.00	1	0		0	0.00
95	HILLCREST - IN	Transmission		138.00	0.00	0.00	0.00	0	0	STATCAP	1	52.79
96	HILLCREST - IN	Transmission		138.00	13.09	0.00	22.40	1	0		0	0.00
97	HUMMEL CREEK - IN	Transmission		138.00	13.09	0.00	13.44	1	0		0	0.00
98	HUMMEL CREEK - IN	Transmission		138.00	69.50	35.00	50.40	1	0		0	0.00
99	ILLINOIS ROAD - IN	Transmission		138.00	13.09	0.00	20.00	1	0		0	0.00
100	INDUSTRIAL PARK - IN	Transmission		34.50	13.00	0.00	22.40	1	0		0	0.00
101	INDUSTRIAL PARK - IN	Transmission		138.00	0.00	0.00	0.00	0	0	STATCAP	1	50.40
102	INDUSTRIAL PARK - IN	Transmission		138.00	13.09	0.00	22.40	1	0		0	0.00
103	IRELAND ROAD - IN	Distribution		138.00	13.09	0.00	20.00	1	0		0	0.00
104	IU PURDUE - IN	Distribution		13.80	4.00	0.00	5.00	1	0		0	0.00
105	JACKSON ROAD - IN	Transmission		138.00	13.09	0.00	32.00	2	0		0	0.00
106	JAY (IM) - IN	Transmission		138.00	0.00	0.00	0.00	0	0	STATCAP	1	57.60
107	JAY (IM) - IN	Transmission		138.00	69.00	34.00	115.00	1	0		0	0.00
108	JEFFERSON (IM) - IN	Transmission		765.00	0.00	0.00	0.00	0	0	REACTOR	3	300.00
109	JOBES - IN	Distribution		34.50	4.00	0.00	9.38	1	0		0	0.00
110	JONES CREEK - IN	Distribution		138.00	12.47	0.00	20.00	1	0		0	0.00
111	KANKAKEE - IN	Transmission		138.00	70.50	36.20	130.00	1	0		0	0.00
112	KANKAKEE - IN	Transmission		138.00	13.09	0.00	22.40	1	0		0	0.00
113	KENDALLVILLE - IN	Transmission		138.00	69.00	13.00	75.00	1	0		0	0.00
114	KENDALLVILLE - IN	Transmission		138.00	0.00	0.00	0.00	0	0	STATCAP	1	43.20
115	KENDALLVILLE - IN	Transmission		69.00	12.00	0.00	10.50	1	0		0	0.00
116	KINGSLAND - IN	Distribution		69.00	13.00	0.00	4.69	1	0		0	0.00
117	LANTERN PARK - IN	Distribution		138.00	13.09	0.00	20.00	1	0		0	0.00
118	LIGONIER - IN	Distribution		138.00	13.09	0.00	29.38	2	0		0	0.00
119	LINCOLN - IN	Transmission		138.00	13.09	0.00	20.00	1	0		0	0.00
120	LINCOLN - IN	Transmission		138.00	70.50	36.20	200.00	1	0		0	0.00
121	LINCOLN - IN	Transmission		138.00	36.20	0.00	45.00	1	0		0	0.00
122	LINWOOD (IM) - IN	Distribution		138.00	13.09	0.00	10.50	1	0		0	0.00
123	LYNN - IN	Distribution		69.00	13.00	0.00	7.00	1	0		0	0.00
124	MAGLEY - IN	Transmission		138.00	69.00	13.00	90.00	1	0		0	0.00
125	MAGLEY - IN	Transmission		69.00	13.00	0.00	9.38	1	0		0	0.00
126	MARION ETHANOL - IN	Distribution		34.50	4.00	0.00	10.50	1	0		0	0.00
127	MARION PLANT - IN	Distribution		34.50	13.00	0.00	22.40	1	0		0	0.00
128	MARION PLANT - IN	Distribution		34.50	0.00	0.00	0.00	0	0	STATCAP	1	8.75
129	MARION PLANT - IN	Distribution		34.50	4.00	0.00	6.00	1	0		0	0.00
130	MAYFIELD - IN	Distribution		138.00	13.09	0.00	20.00	1	0		0	0.00
131	MCCLURE - IN	Distribution		34.50	4.00	0.00	7.50	1	0		0	0.00
132	MCGALLIARD ROAD - IN	Distribution		34.50	13.09	0.00	25.00	1	0		0	0.00
133	MCKINLEY - IN	Transmission		138.00	0.00	0.00	0.00	0	0	STATCAP	1	86.40
134	MCKINLEY - IN	Transmission		69.00	0.00	0.00	0.00	0	0	STATCAP	1	21.60
135	MCKINLEY - IN	Transmission		138.00	13.09	0.00	40.00	2	0		0	0.00
136	MCKINLEY - IN	Transmission		138.00	34.00	0.00	112.00	1	0		0	0.00
137	MCKINLEY - IN	Transmission		138.00	70.50	36.20	130.00	1	0		0	0.00

Line No.	Name and Location of Substation (a)	Character of Substation		VOLTAGE (In MVa)			Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment		
		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVa) (c)	Secondary Voltage (In MVa) (d)	Tertiary Voltage (In MVa) (e)				Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
138	MEADOW LAKE SW - IN	Transmission		345.00	0.00	0.00	0.00	0	0	STATCAP	2	0.00
139	MEADOWBROOK - IN	Transmission		138.00	35.00	0.00	100.00	1	0		0	0.00
140	MIER - IN	Distribution		138.00	13.09	0.00	10.50	1	0		0	0.00
141	MILLER AVENUE - IN	Distribution		34.50	4.00	0.00	8.00	1	0		0	0.00
142	MISSISSINEWA - IN	Distribution		138.00	13.09	0.00	0.00	1	0		0	0.00
143	MODOC - IN	Transmission		69.00	13.09	0.00	5.60	1	0		0	0.00
144	MONROE (IM) - IN	Distribution		69.00	13.00	0.00	7.50	1	0		0	0.00
145	MURRAY - IN	Distribution		69.00	13.00	0.00	5.00	1	0		0	0.00
146	NORTH KENDALLVILLE - IN	Distribution		69.00	12.00	0.00	22.40	1	0		0	0.00
147	NORTHLAND - IN	Distribution		138.00	13.09	0.00	32.00	2	0		0	0.00
148	OLIVE - IN	Transmission		345.00	138.00	34.50	675.00	1	0		0	0.00
149	OLIVE - IN	Transmission		138.00	13.09	0.00	9.38	1	0		0	0.00
150	OSOLO - IN	Transmission		138.00	13.09	0.00	20.00	1	0		0	0.00
151	OSSIAN - IN	Distribution		69.00	13.00	0.00	20.00	1	0		0	0.00
152	PARKWAY - IN	Distribution		34.50	13.00	0.00	4.69	1	0		0	0.00
153	PARNELL - IN	Distribution		34.50	13.09	0.00	12.00	1	0		0	0.00
154	PARNELL - IN	Distribution		34.50	13.00	0.00	20.00	1	0		0	0.00
155	PENDLETON - IN	Transmission		138.00	35.00	0.00	75.00	1	0		0	0.00
156	PENNVILLE - IN	Distribution		138.00	34.00	13.00	7.50	1	0		0	0.00
157	PHILIPS - IN	Distribution		69.00	0.48	0.00	2.50	1	0		0	0.00
158	PINE ROAD - IN	Distribution		138.00	13.09	0.00	20.00	1	0		0	0.00
159	PIPE CREEK - IN	Distribution		138.00	12.00	0.00	20.00	1	0		0	0.00
160	PLEASANT - IN	Distribution		69.00	0.00	0.00	0.00	0	0	STATCAP	1	13.19
161	PLEASANT - IN	Distribution		69.00	13.00	0.00	5.00	1	0		0	0.00
162	PORTLAND (IM) - IN	Distribution		69.00	13.00	0.00	16.80	2	0		0	0.00
163	PRICE - IN	Distribution		69.00	13.09	4.16	12.50	1	0		0	0.00
164	PRICE - IN	Distribution		69.00	13.09	0.00	20.00	1	0		0	0.00
165	RANDOLPH - IN	Transmission		69.00	0.00	0.00	0.00	0	0	STATCAP	1	13.50
166	RANDOLPH - IN	Transmission		138.00	69.00	13.00	56.00	1	0		0	0.00
167	RANDOLPH - IN	Transmission		138.00	13.09	0.00	22.40	1	0		0	0.00
168	RANDOLPH - IN	Transmission		34.50	12.00	0.00	3.75	1	0		0	0.00
169	REED - IN	Distribution		138.00	13.09	0.00	22.40	1	0		0	0.00
170	ROBISON PARK - IN	Transmission		138.00	13.09	0.00	25.00	1	0		0	0.00
171	ROBISON PARK - IN	Transmission		138.00	13.09	0.00	20.00	1	0		0	0.00
172	ROBISON PARK - IN	Transmission		138.00	70.50	36.20	90.00	1	0		0	0.00
173	ROCKPORT - IN	Transmission		34.50	13.00	0.00	1.50	2	0		0	0.00
174	ROSE HILL - IN	Distribution		138.00	13.00	0.00	7.50	1	0		0	0.00
175	ROYERTON - IN	Distribution		138.00	13.09	0.00	10.50	1	0		0	0.00
176	RV CAPITAL - IN	Distribution		138.00	13.09	0.00	15.00	1	0		0	0.00
177	SATURN - IN	Transmission		138.00	13.09	0.00	12.50	1	0		0	0.00
178	SELMA PARKER - IN	Transmission		138.00	13.09	0.00	20.00	1	0		0	0.00
179	SORENSON - IN	Transmission		138.00	13.09	0.00	9.38	1	0		0	0.00
180	SORENSON - IN	Transmission		345.00	138.00	34.00	675.00	1	0		0	0.00
181	SORENSON - IN	Transmission		345.00	138.00	34.50	675.00	1	0		0	0.00
182	SORENSON - IN	Transmission		765.00	345.00	34.50	750.00	0	1		0	0.00
183	SORENSON - IN	Transmission		765.00	345.00	34.50	750.00	0	1		0	0.00
184	SORENSON - IN	Transmission		765.00	345.00	34.50	750.00	0	1		0	0.00
185	SOUTH BEND - IN	Transmission		138.00	69.00	34.00	130.00	1	0		0	0.00
186	SOUTH BEND - IN	Transmission		138.00	0.00	0.00	0.00	0	0	STATCAP	1	52.79
187	SOUTH BEND - IN	Transmission		138.00	13.09	0.00	20.00	1	0		0	0.00
188	SOUTH BERNE - IN	Distribution		69.00	13.09	0.00	12.00	1	0		0	0.00

Line No.	Name and Location of Substation (a)	Character of Substation		VOLTAGE (In MVa)			Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment		
		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVa) (c)	Secondary Voltage (In MVa) (d)	Tertiary Voltage (In MVa) (e)				Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
189	SOUTH DECATUR - IN	Distribution		69.00	13.00	0.00	20.00	1	0		0	0.00
190	SOUTH DECATUR - IN	Distribution		69.00	13.09	0.00	12.00	1	0		0	0.00
191	SOUTH ELWOOD - IN	Transmission		138.00	13.09	0.00	20.00	1	0		0	0.00
192	SOUTH SIDE (MARION) - IN	Distribution		34.50	13.09	0.00	20.00	1	0		0	0.00
193	SOUTH SIDE (SOUTH BEND) - IN	Distribution		138.00	13.09	0.00	20.00	1	0		0	0.00
194	SOUTH SUMMITVILLE - IN	Transmission		69.00	0.00	0.00	0.00	0	0	STATCAP	1	0.00
195	SOUTH SUMMITVILLE - IN	Transmission		69.00	13.09	0.00	20.00	1	0		0	0.00
196	SOYA - IN	Distribution		34.50	4.36	0.00	7.50	1	0		0	0.00
197	SPRING STREET - IN	Distribution		34.50	13.00	0.00	7.50	1	0		0	0.00
198	SPRING STREET - IN	Distribution		34.50	12.00	0.00	12.00	1	0		0	0.00
199	SPY RUN SF6 - IN	Transmission		138.00	13.09	0.00	22.40	1	0		0	0.00
200	SPY RUN SF6 - IN	Transmission		138.00	34.00	0.00	200.00	2	0		0	0.00
201	ST. JOE - IN	Distribution		69.00	13.09	0.00	20.00	1	0		0	0.00
202	STATE STREET - IN	Distribution		138.00	13.09	0.00	25.00	1	0		0	0.00
203	STUDEBAKER - IN	Distribution		138.00	13.80	0.00	36.00	2	0		0	0.00
204	STUDEBAKER - IN	Distribution		138.00	13.09	0.00	12.00	1	0		0	0.00
205	SUMMIT - IN	Distribution		138.00	13.09	0.00	20.00	1	0		0	0.00
206	SUMMIT - IN	Distribution		138.00	13.09	0.00	12.00	1	0		0	0.00
207	SWANSON - IN	Distribution		69.00	34.00	0.00	45.00	2	0		0	0.00
208	SWANSON - IN	Distribution		69.00	0.00	0.00	0.00	0	0	STATCAP	1	14.40
209	THOMAS ROAD - IN	Distribution		69.00	13.09	0.00	64.00	4	0		0	0.00
210	THOMAS ROAD - IN	Distribution		69.00	13.09	0.00	64.00	4	0		0	0.00
211	THREE RIVERS (FTW) - IN	Distribution		34.50	13.00	0.00	10.00	2	0		0	0.00
212	TILLMAN - IN	Transmission		138.00	13.09	0.00	10.00	1	0		0	0.00
213	TILLMAN - IN	Transmission		138.00	36.20	0.00	18.00	1	0		0	0.00
214	TORRINGTON - IN	Distribution		34.50	4.00	0.00	9.07	1	0		0	0.00
215	TRIER - IN	Distribution		138.00	13.09	0.00	20.00	1	0		0	0.00
216	TRI-LAKES - IN	Distribution		69.00	13.00	0.00	3.75	1	0		0	0.00
217	TWENTY FIRST STREET - IN	Distribution		34.50	13.00	0.00	18.75	2	0		0	0.00
218	TWENTY THIRD STREET (IM) - IN	Transmission		34.50	0.00	0.00	0.00	0	0	STATCAP	2	28.80
219	TWENTY THIRD STREET (IM) - IN	Transmission		138.00	69.00	34.00	213.00	2	0		0	0.00
220	TWIN BRANCH 138KV - IN	Transmission		138.00	13.09	0.00	20.00	1	0		0	0.00
221	TWIN BRANCH 345KV - IN	Transmission		345.00	138.00	34.50	675.00	1	0		0	0.00
222	TWIN BRANCH 345KV - IN	Transmission		345.00	137.50	13.20	450.00	1	0		0	0.00
223	TWIN BRANCH 34KV (HYDRO) - IN	Transmission		34.50	4.36	0.00	5005.00	2	0		0	0.00
224	UP RIVER DAM - IN	Distribution		13.80	4.00	0.00	1.50	3	0		0	0.00
225	UP RIVER DAM - IN	Distribution		34.50	4.00	0.00	1.50	3	0		0	0.00
226	UPLAND - IN	Distribution		69.00	13.20	0.00	20.00	1	0		0	0.00
227	UTICA (IM) - IN	Distribution		34.50	13.09	0.00	42.40	2	0		0	0.00
228	WABASH AVENUE - IN	Distribution		69.00	13.09	0.00	20.00	1	0		0	0.00
229	WALLEN - IN	Transmission		138.00	13.09	0.00	45.00	2	0		0	0.00
230	WALLEN - IN	Transmission		138.00	69.00	34.00	90.00	1	0		0	0.00
231	WARREN - IN	Distribution		69.00	12.00	0.00	7.00	1	0		0	0.00
232	WATER POLLUTION - IN	Distribution		34.50	4.00	0.00	7.00	1	0		0	0.00
233	WAYNE TRACE - IN	Distribution		138.00	13.09	0.00	22.40	1	0		0	0.00
234	WAYNEDALE - IN	Distribution		138.00	12.47	0.00	20.00	1	0		0	0.00
235	WAYNEDALE - IN	Distribution		138.00	13.09	0.00	22.40	1	0		0	0.00
236	WEST SIDE - IN	Transmission		138.00	13.09	0.00	42.40	2	0		0	0.00
237	WEST SIDE - IN	Transmission		138.00	69.00	34.00	84.00	1	0		0	0.00
238	WINCHESTER (IM) - IN	Transmission		69.00	0.00	0.00	0.00	0	0	STATCAP	1	10.80
239	WINCHESTER (IM) - IN	Transmission		69.00	13.00	0.00	6.25	1	0		0	0.00

Line No.	Name and Location of Substation (a)	Character of Substation		VOLTAGE (In MVa)			Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment		
		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVa) (c)	Secondary Voltage (In MVa) (d)	Tertiary Voltage (In MVa) (e)				Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
240	WINCHESTER (IM) - IN	Transmission		69.00	13.09	0.00	13.44	1	0		0	0.00
241	WOLF LAKE - IN	Distribution		69.00	13.00	0.00	7.50	1	0		0	0.00
242	WOODS ROAD - IN	Distribution		138.00	12.00	0.00	10.00	1	0		0	0.00
243	ALMENA - MI	Transmission		138.00	70.50	13.09	90.00	1	0		0	0.00
244	ALMENA - MI	Transmission		69.00	12.00	0.00	7.00	1	0		0	0.00
245	ALMENA - MI	Transmission		69.00	34.50	0.00	30.00	1	0		0	0.00
246	BANGOR - MI	Distribution		69.00	12.00	0.00	6.25	1	0		0	0.00
247	BARODA - MI	Distribution		138.00	13.09	0.00	20.00	1	0		0	0.00
248	BENTON HARBOR - MI	Transmission		345.00	137.50	13.80	3600.00	8	0		0	0.00
249	BENTON HARBOR WATERWORKS - MI	Distribution		34.50	13.00	0.00	1.00	3	0		0	0.00
250	BRIDGMAN - MI	Distribution		69.00	12.00	0.00	18.90	2	0		0	0.00
251	BRIDGMAN - MI	Distribution		69.00	0.00	0.00	0.00	0	0	STATCAP	1	14.40
252	BUCHANAN HYDRO STA - MI	Transmission		69.00	34.00	0.00	20.00	1	0		0	0.00
253	BUCHANAN HYDRO STA - MI	Transmission		69.00	12.00	0.00	7.50	1	0		0	0.00
254	CAMERON - MI	Distribution		69.00	34.50	0.00	10.00	0	1		0	0.00
255	COLBY - MI	Transmission		138.00	13.09	0.00	8.40	1	0		0	0.00
256	COLBY - MI	Transmission		34.50	0.00	0.00	0.00	0	0	STATCAP	1	12.00
257	COLBY - MI	Transmission		138.00	69.00	34.50	75.00	1	0		0	0.00
258	COLBY - MI	Transmission		69.00	34.50	0.00	20.00	1	0		0	0.00
259	COREY - MI	Transmission		138.00	69.00	34.50	130.00	1	0		0	0.00
260	COREY - MI	Transmission		69.00	0.00	0.00	0.00	0	0	STATCAP	1	14.40
261	COVERT - MI	Distribution		69.00	13.00	0.00	9.38	1	0		0	0.00
262	CRYSTAL - MI	Distribution		138.00	13.09	0.00	22.40	1	0		0	0.00
263	DC COOK 69/12 - MI	Transmission		69.00	0.00	0.00	0.00	0	0	STATCAP	1	0.00
264	EAST WATERVLIET - MI	Distribution		138.00	13.09	0.00	20.00	1	0		0	0.00
265	FLORENCE ROAD - MI	Distribution		69.00	13.09	0.00	12.00	1	0		0	0.00
266	HAGAR - MI	Distribution		69.00	12.00	0.00	10.50	1	0		0	0.00
267	HARTFORD - MI	Transmission		138.00	70.50	36.20	54.00	1	0		0	0.00
268	HARTFORD - MI	Transmission		138.00	70.50	36.20	54.00	1	0		0	0.00
269	HICKORY CREEK - MI	Transmission		138.00	69.00	34.50	75.00	1	0		0	0.00
270	KENZIE CREEK - MI	Transmission		345.00	137.50	13.80	450.00	1	0		0	0.00
271	LAKE STREET - MI	Transmission		69.00	34.00	0.00	40.00	1	0		0	0.00
272	LAKE STREET - MI	Transmission		69.00	0.00	0.00	0.00	0	0	STATCAP	1	14.40
273	LAKESIDE (MBH) - MI	Distribution		69.00	13.09	0.00	9.38	1	0		0	0.00
274	LAKESIDE (MBH) - MI	Distribution		69.00	12.00	0.00	9.38	1	0		0	0.00
275	LANGLEY (IM) - MI	Distribution		34.50	13.09	0.00	10.00	2	0		0	0.00
276	LANGLEY (IM) - MI	Distribution		34.50	138.00	13.80	14.00	2	0		0	0.00
277	LANGLEY (IM) - MI	Distribution		34.50	34.50	13.80	14.00	2	0		0	0.00
278	MOORE PARK - MI	Transmission		138.00	0.00	0.00	0.00	0	0	STATCAP	1	56.70
279	MOORE PARK - MI	Transmission		138.00	70.50	36.20	54.00	1	0		0	0.00
280	MOORE PARK - MI	Transmission		69.00	0.00	0.00	0.00	0	0	STATCAP	1	16.20
281	MOORE PARK - MI	Transmission		138.00	13.09	0.00	20.00	1	0		0	0.00
282	MURCH - MI	Distribution		69.00	0.00	0.00	0.00	0	0	STATCAP	1	13.20
283	MURCH - MI	Distribution		69.00	12.00	0.00	20.00	1	0		0	0.00
284	NEW BUFFALO - MI	Distribution		69.00	12.00	0.00	30.50	2	0		0	0.00
285	NILES - MI	Transmission		69.00	34.00	0.00	44.80	1	0		0	0.00
286	NILES - MI	Transmission		69.00	0.00	0.00	0.00	0	0	STATCAP	1	14.39
287	NILES - MI	Transmission		69.00	13.09	0.00	20.00	1	0		0	0.00
288	PEARL STREET - MI	Distribution		34.50	12.00	0.00	16.88	2	0		0	0.00
289	PIGEON RIVER - MI	Distribution		69.00	12.00	0.00	20.00	1	0		0	0.00

Line No.	Name and Location of Substation (a)	Character of Substation		VOLTAGE (In MVa)			Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment		
		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVa) (c)	Secondary Voltage (In MVa) (d)	Tertiary Voltage (In MVa) (e)				Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)
290	POKAGON(MBH) - MI	Transmission		138.00	69.00	13.00	115.00	1	0		0	0.00
291	POKAGON(MBH) - MI	Transmission		69.00	13.00	0.00	5.00	1	0		0	0.00
292	POKAGON(MBH) - MI	Transmission		69.00	0.00	0.00	0.00	0	0	STATCAP	1	14.39
293	RICKERMAN ROAD - MI	Distribution		138.00	13.09	0.00	7.50	1	0		0	0.00
294	RIVERSIDE (IM) - MI	Transmission		138.00	13.09	0.00	20.00	1	0		0	0.00
295	RIVERSIDE (IM) - MI	Transmission		138.00	69.00	34.00	45.00	1	0		0	0.00
296	RIVERSIDE (IM) - MI	Transmission		138.00	0.00	0.00	0.00	0	0	STATCAP	1	52.80
297	SAUK TRAIL - MI	Distribution		138.00	13.09	0.00	20.00	1	0		0	0.00
298	SCOTTDALE - MI	Distribution		34.50	13.09	0.00	9.38	1	0		0	0.00
299	SISTER LAKES - MI	Distribution		34.50	13.09	0.00	7.50	1	0		0	0.00
300	SISTER LAKES - MI	Distribution		34.50	12.00	0.00	5.67	1	0		0	0.00
301	SODUS - MI	Distribution		138.00	13.09	0.00	10.50	1	0		0	0.00
302	STEVENSVILLE - MI	Distribution		69.00	13.00	0.00	8.40	1	0		0	0.00
303	STEVENSVILLE - MI	Distribution		69.00	13.09	0.00	12.50	1	0		0	0.00
304	STONE LAKE - MI	Distribution		69.00	12.00	0.00	9.38	1	0		0	0.00
305	STONE LAKE - MI	Distribution		69.00	13.00	0.00	7.00	1	0		0	0.00
306	STUBEY ROAD - MI	Distribution		69.00	0.00	0.00	0.00	0	0	STATCAP	1	14.40
307	THREE OAKS - MI	Distribution		69.00	12.00	0.00	6.25	1	0		0	0.00
308	VALLEY - MI	Transmission		138.00	69.00	34.00	75.00	1	0		0	0.00
309	VICKSBURG - MI	Distribution		69.00	12.00	0.00	9.38	1	0		0	0.00
310	VICKSBURG - MI	Distribution		69.00	13.09	0.00	20.00	1	0		0	0.00
311	WEST STREET - MI	Distribution		138.00	13.09	0.00	20.00	1	0		0	0.00
312	WHEELER STREET - MI	Distribution		69.00	13.00	0.00	8.40	1	0		0	0.00
313	WOLVERINE - MI	Distribution		69.00	13.00	2.40	5.00	1	0		0	0.00
314	WOLVERINE - MI	Distribution		69.00	13.00	2.40	5.00	1	0		0	0.00
315	TotalTransmissionSubstationMember											1,847
316	Total											1,847

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Good or Service (a)	Name of Associated/Affiliated Company (b)	Account(s) Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Administrative and General Expenses - Maintenance	AEPSC [a]	935	5,809,241
3	Administrative and General Expenses - Operation	AEPSC	920-926, 928,930,931	7,730,795
4	AEP Transmission	AEPSC	920,923	1,140,893
5	AEPSC Support Svcs	AEPSC	417	851,179
6	Building and Property Leases	IMTCo	507,567,589	708,683
7	Central Machine Shop	APCo	107,108,163,500,506,512,513,524,530,531,544	2,607,302
8	Chief Commercial Officer	AEPSC	920, 923	1,130,703
9	Chief Executive Officer	AEPSC	920, 923	14,831,382
10	Chief Financial Officer	AEPSC	920, 923	14,737,976
11	Chief Info & Tech Officer	AEPSC	920, 923	13,186,887
12	Civil & Political Activities and Other Svcs	AEPSC	426	926,221
13	Coal Transloading	AEGCo	151	7,108,723
14	Construction Services	AEPSC	107,108,120	80,969,695
15	Construction Services	OPCo	107,108	303,679
16	Customer Accounts Expenses	AEPSC	901-905	9,661,434
17	Distribution Expenses - Maintenance	OPCo	590, 593-598	320,955
18	Distribution Expenses - Operation	AEPSC	580, 582-584, 586-588	4,505,737
19	Expenses of Nonutility Operations	APCo	417	5,338,036
20	Factored Customer A/R Bad Debts	AEP Credit	426	3,846,209
21	Factored Customer A/R Expense	AEP Credit	426	11,264,369
22	Fuel & Storeroom Services	AEPSC	152,163	4,710,309
23	Hydraulic Power Generation - Operation	AEPSC	535, 537-539	958,320
24	Materials and Supplies	OPCo	107,108,154,163,184,570,592,593,595,935	4,162,207
25	Nuclear Power Generation - Maintenance	AEPSC	528,530-532	1,563,280
26	Nuclear Power Generation - Operation	AEPSC	517,520,524	707,523
27	Other Power Supply Expenses	AEPSC	556,557	3,436,942
28	Projects & Services	AEPSC	920,923	1,116,464
29	Rail Car Lease	SWEPCo	186	364,632
30	Rail Car Maintenance	AEGCo	151	1,045,892
31	Survey Handling	AEGCo	501	269,865
32	Transmission Expenses - Maintenance	AEPSC	568,569,591-593,570-573	719,334
33	Transmission Expenses - Operation	AEPSC	560-564,566	7,752,685
34	Utilities	AEPSC	920,930	702,598
35	Research and Other Services	AEPSC	183,186,188	1,603,101
36	Research and Other Services	AEP Texas	184,186	492,148
37	Research and Other Services	PSO	184,186	326,894
38	Research and Other Services	SWEPCO	184,186	290,463
39	Steam Power Generation _Maint	AEPSC	510-514	933,859
40	Steam Power Generation _Oper	AEPSC	500,501,502,506	7,064,294
19				
20	**Non-power Goods or Services Provided for Affiliated**			
21	Barging	AEGCo	417	10,042,001
22	Barging	APCo	417	46,985,215
23	Barging	WPCo	417	7,519,641
24	Building and Property Leases	AEPSC	454	1,676,802

Line No.	Description of the Good or Service (a)	Name of Associated/Affiliated Company (b)	Account(s) Charged or Credited (c)	Amount Charged or Credited (d)
25	Construction Services	AEP Texas	107,108	251,316
26	Construction Services	APCo	107,108	858,763
27	Construction Services	IMTCo	107,108	7,428,278
28	Construction Services	OPCo	107,108	605,239
29	Distribution Expenses - Maintenance	AEP Texas	592-596, 598	297,064
30	Distribution Expenses - Maintenance	APCo	593-596, 598	1,609,270
31	Distribution Expenses - Maintenance	KgPCo	593, 598	255,648
32	Distribution Expenses - Maintenance	KPCo	593, 598	377,020
33	Distribution Expenses - Maintenance	OPCo	592-598	319,736
34	Fleet and Vehicle Charges	AEPSC	188	558,453
35	Fleet and Vehicle Charges	AEP Texas	188	317,456
36	Fuel Carbon Activation	(b) AEGCo	154, 502	2,429,711
37	Fuel Consumed - Ammonia	AEGCo	154, 502	391,772
38	Fuel Consumed Handling	AEGCo	152, 501	5,612,518
39	Materials and Supplies	APCo	154	342,497
40	Rail Car Lease	SWEPCo	151	1,055,445
41	Rockport Joint Books	AEGCo	See Footnote	42,461,690
42	Sodium Bicarbonate Activation	AEGCo	154, 502	5,879,925
43	Transmission Expenses - Maintenance	IMTCo	568-571, 573	2,143,589
44	Transmission Expenses - Operation	IMTCo	560,562,563,566	3,090,680
45	Use of Jointly Owned Facility	IMTCo	454	8,702,399
46	Deferred Credits	AEGCo	253	278,085
42				

Name of Respondent: Indiana Michigan Power Company	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 04/08/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: NameOfAssociatedAffiliatedCompany

Certain managerial and professional services provided by AEPSC are allocated among multiple affiliates. The costs of the services are billed on a direct-charge basis, whenever possible. Costs incurred to perform services that benefit more than one company are allocated to the benefiting companies using one of 80 FERC accepted allocation factors. The allocation factors used to bill for services performed by AEPSC are based upon formulae that consider factors such as number of customers, number of employees, number of transmission miles, number of invoices and other factors. The data upon which these formulae are based is updated monthly, quarterly, semi-annually or annually, depending on the particular factor and its volatility. The billings for service are made at cost and include no compensation for a return on investment.

(b) Concept: NameOfAssociatedAffiliatedCompany

The Rockport Plant is owned 50% by I&M and 50% by AEG. I&M is the operator of the plant and most charges originate on I&M's general ledger. A joint books process then allocates 50% of those charges to AEG.