MICHIGAN PUBLIC SERVICE COMMISSION

ANNUAL REPORT OF ELECTRIC UTILITIES (MAJOR AND NON-MAJOR)

This form is authorized by 1919 PA 419, as amended, authorizes this form being MCL 460.51 et seq.; and 1969 PA 306, as amended, being MCL 24.201 et seq. Filing of this form is mandatory. Failure to complete and submit this form will place you violation of the Acts.

Report submitted for year ending:

December 31, 2012

Present name of respondent:

Indiana Michigan Power Company

Address of principal place of business:

1 Riverside Plaza, Columbus, OH 43215-2373

Utility representative to whom inquires regarding this report may be directed:

Name: Bradley Funk **Title:** Manager of Regulated Accounting

Address: 1 Riverside Plaza

City: Columbus **State:** OH **Zip:** 43215

Telephone, Including Area Code: (614) 716-3162

If the utility name has been changed during the past year:

Prior Name:

Date of Change:

Two copies of the published annual report to stockholders:

[ ] **were forwarded to the Commission**
[x] **will be forwarded to the Commission**

on or about April 30, 2013

Annual reports to stockholders:

[x] **are published**
[ ] **are not published**

FOR ASSISTANCE IN COMPLETION OF THIS FORM:

Contact the Michigan Public Service Commission (Heather Cantin) at (517) 241-0967 or cantinh@michigan.gov OR forward correspondence to:

Regulated Energy Division (Heather Cantin)
4300 W Saginaw
Lansing, MI 48917

MPSC FORM P-521

ANNUAL REPORT OF ELECTRIC UTILITIES, LICENSEES AND OTHERS (Major and Nonmajor)

IDENTIFICATION	
01 Exact Legal Name of Respondent Indiana Michigan Power Company	02 Year of Report December 31, 2012
03 Previous Name and Date of Change (if name changed during year)	
04 Address of Principal Business Office at End of Year (Street, City, St., Zip) 1 Riverside Plaza, Columbus, OH 43215-2373	

05 Name of Contact Person Bradley M. Funk	06 Title of Contact Person Accounting Manager	
07 Address of Contact Person (Street, City, St., Zip) 1 Riverside Plaza, Columbus, OH 43215-2373		
08 Telephone of Contact Person, Including Area Code: (614) 716-3162	09 This Report is: (1) [X] An Original (2) [ ] A Resubmission	10 Date of Report (Mo, Da,Yr)

ATTESTATION

The undersigned officer certifies that he/she has examined the accompanying report; that to the best of his/her knowledge, information, and belief, all statements of fact contained in the accompanying report are true and the accompanying report is a correct statement of the business and affairs of the above named respondent in respect to each and every matter set forth therein during the period from and including January 1 and including December 31 of the year of the report.

01 Name Andrew B. Reis	03 Signature Andrew B. Reis	04 Date Signed (Mo, Da,Yr) April 24, 2013
02 Title Assistant Controller		

LIST OF SCHEDULES (Electric Utility)

1. 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 responses are "none", "not applicable", or "NA".

2. The "M" prefix below denotes those pages where the information requested by the MPSC differs from that requested by FERC. Each of these pages also contains the "M" designation on the page itself.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission		December 31, 2012

LIST OF SCHEDULES (Electric Utility) (Continued)

Title of Schedule (a)		Reference Page No. (b)	Remarks (c)
BALANCE SHEET SUPPORTING SCHEDULES (Liabilities and Other Credits) (Continued)			
Other Paid-In Capital		253	FERC Form 1
Discount on Capital Stock		254	NA
Capital Stock Expense		254	NA
Securities Issued and Redeemed During the Year	M	255	
Long-Term Debt		256-257	FERC Form 1
Payable to Associated Companies	M	260B	
Reconciliation of Reported Net Income with Taxable Income for Federal Income Tax	M	261A-B	
Calculation of Federal Income Tax			
Taxes Accrued, Prepaid and Charged During Year	M	262-263	FERC Form 1
Distribution of Taxes Charged			
Accumulated Deferred Investment Tax Credits		266-267	FERC Form 1
Miscellaneous Current and Accrued Liabilities	M	268	
Other Deferred Credits		269	FERC Form 1
Accumulated Deferred Income Taxes - Accelerated Amortization Property		272-273	FERC Form 1
Accumulated Deferred Income Taxes - Other Property		274-275	FERC Form 1
Accumulated Deferred Income Taxes - Other		276A-B	FERC Form 1
Other Regulatory Liabilities		278	FERC Form 1
Gain or Loss on Disposition of Property	M	280	
Particulars Concerning Certain Other Income Accounts	M	282	
INCOME ACCOUNT SUPPORTING SCHEDULES			
Electric Operating Revenues	M	300-301	
Customer Choice Electric Operating Revenues	M	302-303	
Sales of Electricity by Rate Schedules	M	304	
Customer Choice Sales of Electricity by Rate Schedules	M	305	
Sales for Resale		310-311	FERC Form 1
Electric Operation and Maintenance Expenses		320-323	
Number of Electric Department Employees		323	
Purchased Power		326-327	FERC Form 1
Transmission of Electricity for Others		328-330	FERC Form 1
Miscellaneous Revenue	M	331	
Transmission of Electricity by Others		332	FERC Form 1
Lease Rentals Charged	M	333	
Miscellaneous General Expenses - Electric		335	FERC Form 1
Depreciation and Amortization of Electric Plant		336	FERC Form 1
Depreciation and Amortization of Electric Plant		337	FERC Form 1
Particulars Concerning Certain Income Deduction and Interest Charges Accounts	M	340	
Expenditures For Certain Civic, Political and Related Activities	M	341	
Extraordinary Items	M	342	NA
COMMON SECTION			
Regulatory Commission Expenses		350-351	FERC Form 1
Research, Development and Demonstration Activities		352-353	FERC Form 1
Distribution of Salaries and Wages		354-355	FERC Form 1
Common Utility Plant and Expenses		356	
Charges for Outside Professional and Consultative Services	M	357	
ELECTRIC PLANT STATISTICAL DATA			
Monthly Transmission System Peak Load		400	NA
Electric Energy Account		401a	FERC Form 1
Monthly Peaks and Output		401b	FERC Form 1
Steam-Electric Generating Plant Statistics (Large Plants)		402-403	FERC Form 1
Hydroelectric Generating Plant Statistics (Large Plants)		406-407	NA
Pumped Storage Generating Plant Statistics (Large Plants)		408-409	NA
Generating Plant Statistics (Small Plants)		410-411	FERC Form 1
Changes Made or Scheduled to be Made in Generating Plants	M	412	
Steam-Electric Generating Plant Statistics (Large Plants)	M	413A/B	

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2012

LIST OF SCHEDULES (Electric Utility) (Continued)

Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
Generating Plant Statistics - Pumped Storage	416-418	NA
Generating Plant Statistics - Internal Combustion Engine	420-421	NA
Transmission Line Statistics	422-423	FERC Form 1
Transmission Lines Added During Year	424-425	FERC Form 1
Substations	426-427	FERC Form 1
Affiliated Transactions	429	FERC Form 1
Electric Distribution Meters and Line Transformers	429a	
Environmental Protection Facilities	430	NA
Environmental Protection Expenses	431	NA
Footnote Data	450	

As noted in column C, certain pages filed by Indiana Michigan Power Company are copies of the FERC Form 1. In such instances, the requirements of the FERC Form 1 meet or exceed those of the MPSC Form P-521.

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31,2012

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.

Andrew B. Reis, Assistant Controller

1 Riverside Plaza

Columbus, OH 43215

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 date organized.

Indiana - February 21, 1925

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.

None

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

Electric - Indiana

Electric - 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...Enter date when such independent accountant was initially engaged: ____________________.

(2) [X] No

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2012

CONTROL OVER RESPONDENT & OTHER ASSOCIATED COMPANIES

1. If any corporation, business trust, or similar organization or combination of such organizations jointly held control over the respondent at end of 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.

2. List any entities which respondent did not control either directly or indirectly and which did not control respondent but which were associated companies at any time during the year.

American Electric Power Company, Inc. - Ownership of 100% of the respondent's common stock

The following list of subsidiaries was extracted from Exhibit 21 of the company's Form 10-K as filed with the SEC.

Subsidiaries of American Electric Power Company, Inc., As of December 31, 2012

Each company shown indented is owned by the company immediately above it. Subsidiaries not indented are directly owned by the American Electric Power Company, Inc.

American Electric Power Service Corporation
AEP C&I Company, LLC
AEP Coal, Inc.
AEP Credit, Inc.
AEP Fiber Venture, LLC
AEP Generating Company
AEP Investments, Inc.
AEP Nonutility Funding LLC
AEP Pro Serv, Inc.
AEP Resources, Inc.
AEP T&D Services, LLC
AEP Transmission Holding Company, LLC
AEP Utilities, Inc.
  AEP Texas Central Company
    AEP Texas Central Transition Funding LLC
    AEP Texas Central Transition Funding II LLC
    AEP Texas Central Transition Funding III LLC
  AEP Texas North Company
    AEP Texas North Generation Company LLC
  CSW Energy, Inc.
  CSW Energy Services, Inc.
AEP Utility Funding LLC
Appalachian Power Company
  Cedar Coal Co.
  Central Appalachian Coal Company
  Central Coal Company
  Southern Appalachian Coal Company

CONTROL OVER RESPONDENT & OTHER ASSOCIATED COMPANIES

Franklin Real Estate Company
Indiana Michigan Power Company
  Blackhawk Coal Company
  Price River Coal Company, Inc.
Kentucky Power Company
Kingsport Power Company
Ohio Power Company
  AEP Generation Resources Inc.
  Cardinal Operating Company
  Central Coal Company
  Conesville Coal Preparation Company
  Distribution Vision 2010, LLC
  Ohio Valley Electric Corporation
    Indiana-Kentucky Electric Corporation
Ohio Valley Electric Corporation
  Indiana-Kentucky Electric Corporation
Power Tree Carbon Company, LLC
Public Service Company of Oklahoma
Southwestern Electric Power Company
  Arkansas Coalition for Affordable & Reliable Electricity, LLC
  Dolet Hills Lignite Company, LLC
  Oxbow Lignite Company, LLC
  Southwestern Arkansas Utilities Corporation
  The Arklahoma Corporation
Wheeling Power Company

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	
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Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2012

OFFICERS AND EMPLOYEES

1. Report below the name, title and salary for the five executive officers
2. Report in column (b) salaries and wages accrued during the year including deferred compensation.
3. In column (c) report any other compensation provided, such as bonuses, car allowance, stock options and rights, savings contribution, etc., and explain in a footnote what the amounts represent. Provide type code for other compensation in column (d).
4. If a change was made during the year in the incumbent of any position, show the name and total remuneration of the previous incumbent and the date the change in incumbency occurred.
5. Upon request, the Company will provide the Commission with supplemental information on officers and other employees and salaries.

Line	Name and Title	Base Wages	Other Compensation	Type of Other Compensation	Total Compensation
	(a)	(b)	(c)	(d)	(e)
1	Nicholas K. Akins	903,461	1,500,000	A	7,286,490
	President and Chief Executive Officer		74,250	B	
			4,600,008	C	
			208,771	D	
2	Brian X. Tierney	652,500	800,000	A	3,627,587
	Executive Vice President & Chief		49,467	B	
	Financial Officer		1,896,860	C	
			228,760	D	
3	Robert P. Powers	652,500	800,000	A	3,996,528
	Executive Vice President & Chief		49,500	B	
	Operating Officer		1,896,860	C	
			597,668	D	
4	Dennis E. Welch	465,283	415,000	A	1,921,254
	Executive Vice President & Chief		28,096	B	
	External Officer		920,291	C	
			92,584	D	
5	David M. Feinberg	451,731	450,000	A	1,826,943
	Executive Vice President & General Counsel		27,606	B	
			857,807	C	
			39,799	D	

Compensation Type Codes:

A = Executive Incentive Compensation
B = Incentive Plan (Matching Employer Contribution)
C = Stock Plans
D = Other Reimbursements

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31,2012

DIRECTORS

1. Report below any information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.

2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Name and Title of Director (a)	Principal Business Address (b)	# of Directors Meetings During Yr (c)	Fees During Yr (d)
Nicholas K. Akins - Chief Executive Officer *** Chairman of the Board **	Columbus, Ohio	N/A	0
Mark C. McCullough - Vice President ***	Columbus, Ohio	N/A	0
Allen R. Glassburn	Fort Wayne, Indiana	N/A	0
Marc E. Lewis - Vice President External Affairs	Fort Wayne, Indiana	N/A	0
Robert P. Powers - Vice President***	Columbus, Ohio	N/A	0
Brian X. Tierney - Vice President *** - Chief Financial Officer	Columbus, Ohio	N/A	0
J. Edward Ehler - Vice President Distribution Region Operations	Fort Wayne, Indiana	N/A	0
Lisa M. Barton - Vice President ***	Columbus, Ohio	N/A	0
Scott M. Krawec	Fort Wayne, Indiana	N/A	0
Sarah L. Bodner	Fort Wayne, Indiana	N/A	0
Paul Chodak, III - President & COO	Fort Wayne, Indiana	N/A	0
Daniel V. Lee - VP - Generation Assets	Fort Wayne, Indiana	N/A	0

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2012

SECURITY HOLDERS AND VOTING POWERS

1. (A) Give the names and addresses of the 10 security holders of the respondent who, at the date of the latest closing of the stock book or compilation of list of stockholders of the respondent, prior to the end of the year, had the highest voting powers in the respondent, and state the number of votes which each would have had the right to cast on that date if a meeting were then in order. If any such holder held in trust, give in a footnote the known particulars of the trust (whether voting trust, etc.), duration of trust, and principal holders of beneficiary interests in the trust. If the stock book was not closed or a list of stockholders was not compiled within one year prior to the end of the year, or if since the previous compilation of a list of stockholders, some other class of security has become vested with voting rights, then show such 10 security holders as of the close of the year. Arrange the names of the security holders in the order of voting power, commencing with the highest. Show in column (a) the titles of officers and directors included in such list of 10 security holders.

1. (B) Give also the name and indicate the voting powers resulting from ownership of securities of the respondent of each officer and director not included in the list of 10 largest security holders.

2. If any security other than stock carries voting rights, explain in a supplemental statement the circumstances whereby such security became vested with voting rights and give other important particulars (details) concerning the voting rights of such security. State whether voting rights are actual or contingent; if contingent, describe the contingency.

3. If any class or issue of security has any special privileges in the election of directors, trustees or managers, or in the determination of corporate action by any method, explain briefly in a footnote.

4. Furnish particulars (details) concerning any options, warrants, or rights outstanding at the end of the year for others to purchase securities of the respondent or any securities or other assets owned by the respondent, including prices, expiration dates, and other material information relating to exercise of the options, warrants, or rights. Specify the amount of such securities or assets so entitled to be purchased by any officer, director, associated company, or any of the ten largest security holders. This instruction is inapplicable to convertible securities or to any securities substantially all of which are outstanding in the hands of the general public where the options, warrants, or rights were issued on a prorata basis.

1. Give date of the latest closing of the stock book prior to end of year, and state the purpose of such closing:

Stock books do not close

2. State the total number of votes cast at the latest general proxy meeting prior to the end of year for election of directors of the respondent and number of such votes cast by proxy:

Total: 1,400,000

By Proxy: 1,400,000

3. Give the date and place of such meeting:

April 24, 2012 in Tulsa, Oklahoma

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A resubmission	Date of Report (Mo, Da, Yr)	Year of Report December 31, 2012

SECURITY HOLDERS AND VOTING POWERS (Continued)

Line	Name (Title) and Address of Security Holder (a)	VOTING SECURITIES Number of votes as of (date): Total Votes (b)	Common Stock (c)	Preferred Stock (d)	Other (e)
4	TOTAL votes all voting securities	1,400,000	1,400,000		
5	TOTAL number of security holders	1	1		
6	TOTAL votes of security holders listed below				
7	American Electric Power Company, Inc.	1,400,000	1,400,000		
8	1 Riverside Plaza				
9	Columbus, Ohio 43215				
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RESPONSE/NOTES TO INSTRUCTION

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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 Page 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.

PAGE 108 INTENTIONALLY LEFT BLANK
SEE PAGE 109 FOR REQUIRED INFORMATION.

1.

Date Acquired Or Extended	Community	Period of Franchise & Termination	Consideration
Renewed on March 30, 2012	Lincoln Charter Township, Berrien County, MI	Ten (10) year Franchise renewal expiring on March 30, 2022	None
Renewed on October 23, 2012	Oshtemo Charter Township, Kalamazoo County, MI	Thirty (30) year Franchise renewal expiring on November 1, 2042	None
Renewed on November 12, 2012	Texas Charter Township, Kalamazoo County, MI	Ten (10) year Franchise renewal expiring on January 11, 2023 (based upon the effective date)	None
Renewed on December 10, 2012	Hagar Township, Berrien County, MI	Ten (10) year Franchise renewal expiring on November 11, 2023 (based upon the effective date)	None

2. None

3. None

4. None

5. None

6. Letter of Credit ($150,000) issued by American Electric Power Company, Inc. on behalf of Indiana Michigan Power Company to benefit Travelers Insurance/DC Cook Workers Compensation (FERC Authority (Docket No. ES11-50-000)

   Indiana Utility Regulatory Commission Authority (Cause No. 44116)
   Three year $110M local bank term loan at LIBOR +1.50%, due May 30, 2015

   Indiana Utility Regulatory Commission Authority (Cause No. 44025)
   $109.5M 3-Month LIBOR +1.50% fuel capital lease, due October 27, 2016

7. None

8. Tanners Creek employees represented by UWUA Local #418 were provided with a 2% general wage increase effective February 15, 2012

   USW Local #13729 employees were provided with a 2% general wage increase effective December 1, 2012

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

10. None

11. (Reserved)

12. Not Used

13. Nicholas K. Akins appointed as Chairman of the Board effective January 1, 2012
David M. Feinberg appointed as Secretary effective January 1, 2012
Mark C. McCullough appointed as Director effective January 1, 2012
Scott N. Smith appointed as Vice President effective January 26, 2012
Anne M. Vogel resigned as Assistant Secretary effective March 13, 2012
Allen R. Glassburn appointed as Vice President – Finance and Regulatory eff. April 25, 2012
Allen R. Glassburn resigned as Director and Vice President effective December 31, 2012
Michael H. Carlson resigned as Vice President effective December 31, 2012
Barbara D. Radous resigned as Vice President effective December 31, 2012
Charles E. Zebula resigned as Treasurer effective December 31, 2012

14. Proprietary capital ratio exceeds 30%

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) / /	End of 2012/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)	200-201	7,146,373,703	6,884,397,631
3	Construction Work in Progress (107)	200-201	341,062,641	236,095,869
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		7,487,436,344	7,120,493,500
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	3,494,503,152	3,424,425,300
6	Net Utility Plant (Enter Total of line 4 less 5)		3,992,933,192	3,696,068,200
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	131,795,466	97,708,873
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		119,118,515	124,839,783
10	Spent Nuclear Fuel (120.4)		224,950,629	255,621,386
11	Nuclear Fuel Under Capital Leases (120.6)		176,065,156	188,705,956
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	338,796,232	362,124,415
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		313,133,534	304,751,583
14	Net Utility Plant (Enter Total of lines 6 and 13)		4,306,066,726	4,000,819,783
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		31,134,649	29,276,858
19	(Less) Accum. Prov. for Depr. and Amort. (122)		16,051,403	14,149,385
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	23,725,077	23,490,770
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	5,066,281	7,848,512
24	Other Investments (124)		16,146,290	22,793,024
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		1,705,772,402	1,591,731,686
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		23,428,713	29,345,323
31	Long-Term Portion of Derivative Assets – Hedges (176)		140,058	16,746
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		1,789,362,067	1,690,353,534
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		1,555,377	1,013,372
36	Special Deposits (132-134)		6,607,488	10,318,361
37	Working Fund (135)		6,200	6,300
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		61,689,515	72,346,209
41	Other Accounts Receivable (143)		15,981,870	18,250,490
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		229,449	1,749,514
43	Notes Receivable from Associated Companies (145)		103,619,364	90,442,321
44	Accounts Receivable from Assoc. Companies (146)		77,420,899	88,552,840
45	Fuel Stock (151)	227	50,571,903	51,129,732
46	Fuel Stock Expenses Undistributed (152)	227	2,834,549	1,849,711
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	152,386,081	146,238,660
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	3,162,314	3,057,394
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	44,664,483	34,476,260

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)(Continued)

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)
53	(Less) Noncurrent Portion of Allowances		5,066,281	7,848,512
54	Stores Expense Undistributed (163)	227	0	0
55	Gas Stored Underground - Current (164.1)		0	0
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		10,850,236	6,883,077
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	7,152,974
60	Rents Receivable (172)		87,204	114,584
61	Accrued Utility Revenues (173)		11,217,651	14,779,580
62	Miscellaneous Current and Accrued Assets (174)		125,172,733	72,975,502
63	Derivative Instrument Assets (175)		50,342,631	61,237,360
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		23,428,713	29,345,323
65	Derivative Instrument Assets - Hedges (176)		199,814	276,554
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		140,058	16,746
67	Total Current and Accrued Assets (Lines 34 through 66)		689,505,811	642,141,186
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		8,882,013	9,882,271
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	0
72	Other Regulatory Assets (182.3)	232	561,922,918	630,142,964
73	Prelim. Survey and Investigation Charges (Electric) (183)		38,133,774	95,664
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		0	0
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	40,447,626	38,328,279
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		13,801,938	15,078,694
82	Accumulated Deferred Income Taxes (190)	234	832,086,463	774,052,033
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		1,495,274,732	1,467,579,905
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		8,280,209,336	7,800,894,408

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)	250-251	56,583,866	56,583,866
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		4,234,635	4,234,635
7	Other Paid-In Capital (208-211)	253	976,661,804	976,661,804
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	0	0
11	Retained Earnings (215, 215.1, 216)	118-119	795,283,533	751,952,003
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-104,879	-230,765
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-28,884,204	-28,221,410
16	Total Proprietary Capital (lines 2 through 15)		1,803,774,755	1,760,980,133
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	0	0
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	1,837,678,888	1,827,992,520
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		4,388,646	4,907,418
24	Total Long-Term Debt (lines 18 through 23)		1,833,290,242	1,823,085,102
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		115,314,860	140,888,065
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		111,227	74,898
29	Accumulated Provision for Pensions and Benefits (228.3)		98,469,485	181,037,980
30	Accumulated Miscellaneous Operating Provisions (228.4)		967,231	4,516,050
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		13,614,204	8,050,831
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		283,716	10,820,041
34	Asset Retirement Obligations (230)		1,192,313,286	1,013,121,583
35	Total Other Noncurrent Liabilities (lines 26 through 34)		1,421,074,009	1,358,509,448
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		208,701,248	113,062,717
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		104,673,457	81,153,568
41	Customer Deposits (235)		31,142,043	30,695,644
42	Taxes Accrued (236)	262-263	40,058,941	39,814,135
43	Interest Accrued (237)		28,921,543	29,444,022
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report Is:	Date of Report (mo, da, yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	end of 2012/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)(continued)

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)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		4,757,129	6,480,745
48	Miscellaneous Current and Accrued Liabilities (242)		150,642,980	140,691,691
49	Obligations Under Capital Leases-Current (243)		89,395,521	78,519,767
50	Derivative Instrument Liabilities (244)		24,960,732	23,691,329
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		13,614,204	8,050,831
52	Derivative Instrument Liabilities - Hedges (245)		20,454,658	12,159,717
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		283,716	10,820,041
54	Total Current and Accrued Liabilities (lines 37 through 53)		689,810,332	536,842,463
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		0	0
57	Accumulated Deferred Investment Tax Credits (255)	266-267	48,130,448	52,632,906
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	65,663,247	62,469,260
60	Other Regulatory Liabilities (254)	278	550,048,798	493,685,208
61	Unamortized Gain on Reaquired Debt (257)		18,403	20,115
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	246,285	262,768
63	Accum. Deferred Income Taxes-Other Property (282)		995,757,206	867,361,701
64	Accum. Deferred Income Taxes-Other (283)		872,395,611	845,045,304
65	Total Deferred Credits (lines 56 through 64)		2,532,259,998	2,321,477,262
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		8,280,209,336	7,800,894,408

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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

5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin 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.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

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)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	2,102,317,790	2,128,984,087		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	1,448,839,540	1,391,932,163		
5	Maintenance Expenses (402)	320-323	172,562,427	229,883,100		
6	Depreciation Expense (403)	336-337	119,436,675	108,272,070		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	4,030,977	3,976,605		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	20,206,204	19,172,994		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		2,945,611	1,972,806		
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	73,264,445	77,862,981		
15	Income Taxes - Federal (409.1)	262-263	-2,962,664	-76,271,102		
16	- Other (409.1)	262-263	-2,137,209	-2,709,590		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	434,390,785	443,210,765		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	382,595,295	307,429,077		
19	Investment Tax Credit Adj. - Net (411.4)	266	-4,502,458	-2,783,392		
20	(Less) Gains from Disp. of Utility Plant (411.6)		2,395,353	142,074		
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)		938	3,484		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		11,711,667	11,667,707		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,892,794,414	1,898,612,472		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		209,523,376	230,371,615		

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

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 purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders 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.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
2,102,317,790	2,128,984,087					2
						3
1,448,839,540	1,391,932,163					4
172,562,427	229,883,100					5
119,436,675	108,272,070					6
4,030,977	3,976,605					7
20,206,204	19,172,994					8
						9
						10
						11
2,945,611	1,972,806					12
						13
73,264,445	77,862,981					14
-2,962,664	-76,271,102					15
-2,137,209	-2,709,590					16
434,390,785	443,210,765					17
382,595,295	307,429,077					18
-4,502,458	-2,783,392					19
2,395,353	142,074					20
						21
938	3,484					22
						23
11,711,667	11,667,707					24
1,892,794,414	1,898,612,472					25
209,523,376	230,371,615					26

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		209,523,376	230,371,615		
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)		118,819,972	121,007,840		
34	(Less) Expenses of Nonutility Operations (417.1)		108,114,338	113,709,695		
35	Nonoperating Rental Income (418)		446,308	217,495		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	125,886	-41,619		
37	Interest and Dividend Income (419)		1,602,355	2,947,054		
38	Allowance for Other Funds Used During Construction (419.1)		9,723,922	15,395,278		
39	Miscellaneous Nonoperating Income (421)		2,832,635	-514,407		
40	Gain on Disposition of Property (421.1)		492,154	988,254		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		25,928,894	26,290,200		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)			82,538		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		1,655,376	2,026,494		
46	Life Insurance (426.2)					
47	Penalties (426.3)		298,557	26,853		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,090,205	1,178,933		
49	Other Deductions (426.5)		13,318,100	10,636,924		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		16,362,238	13,951,742		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	7,393,303	4,410,520		
53	Income Taxes-Federal (409.2)	262-263	-3,721,179	-1,679,422		
54	Income Taxes-Other (409.2)	262-263	-435,740	245,654		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	6,447,609	7,620,935		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	5,107,546	8,577,249		
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)		4,576,447	2,020,438		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		4,990,209	10,318,020		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		90,701,590	92,125,153		
63	Amort. of Debt Disc. and Expense (428)		2,372,191	2,222,601		
64	Amortization of Loss on Reaquired Debt (428.1)		1,483,709	1,548,025		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)		1,712	1,712		
67	Interest on Debt to Assoc. Companies (430)			24,245		
68	Other Interest Expense (431)		6,217,699	2,935,674		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		4,717,308	7,838,235		
70	Net Interest Charges (Total of lines 62 thru 69)		96,056,169	91,015,751		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		118,457,416	149,673,884		
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)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		118,457,416	149,673,884		

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Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report December 31, 2012

RECONCILIATION OF DEFERRED INCOME TAX EXPENSE

1. Report on this page the charges to accounts 410, 411 and 420 reported in the contra accounts 190, 281, 282, 283 and 284.

2. The charges to the subaccounts of 410 and 411 found on pages 114-117 should agree with the subaccount totals reported on these pages.

In the event the deferred income tax expenses reported on pages 114-117 do not directly reconcile with the amounts found on these pages, then provide the additional information requested in instruction #3, on a separate page.

Line No.		Electric Utility	Gas Utility
1	Debits to Account 410 from:		
2	Account 190	124,078,128	
3	Account 281	317	
4	Account 282	168,778,756	
5	Account 283	141,533,584	
6	Account 284		
7	Reconciling Adjustments		
8	TOTAL Account 410.1 (on pages 114-115 line 17)	**434,390,785**	**0**
9	TOTAL Account 410.2 (on page 117 line 55)		
10	Credits to Account 411 from:		
11	Account 190	191,826,847	
12	Account 281	16,800	
13	Account 282	56,684,016	
14	Account 283	134,067,632	
15	Account 284		
16	Reconciling Adjustments		
17	TOTAL Account 411.1 (on page 114-115 line 18)	**382,595,295**	**0**
18	TOTAL Account 411.2 (on page 117 line 56)		
19	Net ITC Adjustment:		
20	ITC Utilized for the Year DR		
21	ITC Amortized for the Year CR	(4,502,458)	
22	ITC Adjustments:		
23	Adjust last year's estimate to actual per filed return		
24	Other (specify)		
25	Net Reconciling Adjustments Account 411.4*	**(4,502,458)**	**0**
26	Net Reconciling Adjustments Account 411.5**		
27	Net Reconciling Adjustments Account 420***		

* on pages 114-15 line 19   ** on page 117 line 57   *** on page 117 line 58

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report December 31, 2012

RECONCILIATION OF DEFERRED INCOME TAX EXPENSE

3. (a) Provide a detailed reconciliation of the applicable deferred income tax expense subaccount(s) reported on pages 114-117 with the amount reported on these pages. (b) Identify all contra accounts (other than accounts 190 and 281-284).

(c) Identify the company's regulatory authority to utilize contra accounts other than accounts 190 or 281-284 for the recording of deferred income tax expense(s).

Other Utility	Total Utility	Other Income	Total Company	Line No.
				1
	124,078,128	2,569,306	126,647,434	2
	317		317	3
	168,778,756	21,865	168,800,621	4
	141,533,584	3,856,438	145,390,022	5
				6
				7
0	**434,390,785**			8
		6,447,609		9
				10
	191,826,847	2,568,933	194,395,780	11
	16,800		16,800	12
	56,684,016	3,150	56,687,166	13
	134,067,632	2,535,463	136,603,095	14
				15
				16
0	**382,595,295**			17
		5,107,546		18
				19
				20
	(4,502,458)		(4,502,458)	21
				22
				23
				24
0	**(4,502,458)**	**0**		25
		0		26
		0		27

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, 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 of 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 in 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, include them on pages 122-123.

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		749,280,784	675,141,591
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		118,331,530	149,715,503
17	Appropriations of Retained Earnings (Acct. 436)			
18	Reclassification of Appropriated Retained Earnings-Amort. Reserve-Federal	215.1	-315,479	(265,394)
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-315,479	(265,394)
23	Dividends Declared-Preferred Stock (Account 437)			
24	Preferred Stock Series 4-1/8%	238		(208,927)
25	Preferred Stock Series 4.12%	238		(41,749)
26	Preferred Stock Series 4.56%	238		(60,240)
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			(310,916)
30	Dividends Declared-Common Stock (Account 438)			
31	Dividends Declared - Common Stock		-75,000,000	(75,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-75,000,000	(75,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		792,296,835	749,280,784
	APPROPRIATED RETAINED EARNINGS (Account 215)			

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, 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 of 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 in 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, include them on pages 122-123.

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)
39				
40				
41				
42				
43				
44				
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)		2,986,698	2,671,219
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		2,986,698	2,671,219
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		795,283,533	751,952,003
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-230,765	(189,146)
50	Equity in Earnings for Year (Credit) (Account 418.1)		125,886	(41,619)
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)		-104,879	(230,765)

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 Instruction 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)	118,457,416	149,673,884
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	143,673,856	131,421,669
5	Amortization of Regulatory Debits and Credits	2,945,611	1,972,806
6	Amortization of Nuclear Fuel	142,586,921	143,343,197
7	Accretion of Asset Retirement Obligations	11,711,667	11,667,707
8	Deferred Income Taxes (Net)	53,135,553	134,825,374
9	Investment Tax Credit Adjustment (Net)	-4,502,458	-2,783,392
10	Net (Increase) Decrease in Receivables	30,125,870	51,272,794
11	Net (Increase) Decrease in Inventory	-9,397,181	37,031,458
12	Net (Increase) Decrease in Allowances Inventory	-10,188,223	4,529,161
13	Net Increase (Decrease) in Payables and Accrued Expenses	27,372,601	-25,350,259
14	Net (Increase) Decrease in Other Regulatory Assets	23,194,089	13,622,411
15	Net Increase (Decrease) in Other Regulatory Liabilities	2,754,027	-12,910,922
16	(Less) Allowance for Other Funds Used During Construction	9,723,922	15,395,278
17	(Less) Undistributed Earnings from Subsidiary Companies	125,886	-41,619
18	Other (provide details in footnote):	-79,852,099	-52,070,367
19	Mark-to-Market of Risk Management Contracts	12,164,133	-1,589,853
20	Pension Contributions to Qualified Plan Trust	-22,285,000	-52,582,000
21	Deferred Cook Fire Costs, net of Insurance Proceeds	-8,465,037	18,282,259
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	423,581,938	535,002,268
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-322,533,951	-308,637,096
27	Gross Additions to Nuclear Fuel	-109,403,450	-113,682,836
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	-1,784,562	-20,322
30	(Less) Allowance for Other Funds Used During Construction	-9,723,922	-15,395,278
31	Other (provide details in footnote):		
32			
33	Acquired Assets	-895,977	-1,171,607
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-424,894,018	-408,116,583
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	7,664,444	35,650,306
38			
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	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)	-1,045,422,064	-1,166,690,088
45	Proceeds from Sales of Investment Securities (a)	987,549,727	1,110,909,126

Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) / /	End of 2012/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 Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation	10	142
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):	22,555,870	12,687,473
54	(Increase)/Decrease in Other Special Deposits	77	3,172
55	Notes Receivable from Associated Companies	-13,177,043	-90,442,321
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-465,722,997	-505,998,773
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	110,000,000	77,000,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65	Long Term Issuance Costs	-1,599,702	-1,002,858
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):	109,780,562	110,050,506
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	218,180,860	186,047,648
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-100,497,896	-82,506,799
74	Preferred Stock		-8,469,727
75	Common Stock		
76	Other (provide details in footnote):		
77	Notes Payable to Associated Companies		-48,104,996
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock		-310,916
81	Dividends on Common Stock	-75,000,000	-75,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	42,682,964	-28,344,790
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	541,905	658,705
87			
88	Cash and Cash Equivalents at Beginning of Period	1,019,672	360,967
89			
90	Cash and Cash Equivalents at End of period	1,561,577	1,019,672

Schedule Page: 120 Line No.: 18 Column: b

	2012 Cash Flow Incr/Decr	2011 Cash Flow Incr/Decr
Utility Plant, Net	(148,402,408)	(132,694,756)
Property and Investments, Net	6,737,522	(306,057)
Margin Deposits	3,710,796	5,166,496
Prepayments	10,206,105	16,650,684
Accrued Utility Revenues, Net	3,561,929	4,669,875
Miscellaneous Current and Accr Assets	(6,443,480)	(2,412,637)
Unamortized Debt Expense	2,514,710	2,326,306
Other Deferred Debits, Net	(1,484,225)	(1,643,764)
Other Comprehensive Income, Net	3,562,374	5,022,437
Unamortized Discount/Premium on LTD	518,772	520,755
Accumulated Provisions - Misc	(2,955,620)	1,461,735
Current and Accrued Liabilities, Net	15,954,098	23,916,331
Other Deferred Credits, Net	32,667,328	25,252,228
Total	(79,852,099)	(52,070,367)

Schedule Page: 120 Line No.: 37 Column: b

	2012	2011
Transformer Sales - Affiliated Companies	230,671	217,233
Meter Sales - Affiliated Companies	974,331	224,151
Rotor Sales - Affiliated Companies	1,810,337	-
Sale of Former Breed Plant Land - Non Affiliate	4,368,747	-
Transco Transfer of Assets	280,358	-
Towboat/Barge Sales - Non-Affiliated Companies	-	33,152,584
Land Sale - 13.16 Acres to City of Mishawaka	-	191,517
Sale of Bluff Point Wind Project	-	1,600,569
Royal Bank of Scotland Operating Lease	-	264,252
Total	7,664,444	35,650,306

Schedule Page: 120 Line No.: 53 Column: b

	2012	2011
Energy Insurance Services Reimbursement	4,843,575	1,520,009
Department of Energy Proceeds	17,712,295	11,167,464
Total	22,555,870	12,687,473

Schedule Page: 120 Line No.: 67 Column: b

	2012	2011
Proceeds on Nuclear Fuel Sale/Leaseback	109,500,000	109,975,000
Proceeds on Capital Leaseback	280,562	75,506
Total	109,780,562	110,050,506

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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)
1	Balance of Account 219 at Beginning of Preceding Year				(12,201,760)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				552,794
3	Preceding Quarter/Year to Date Changes in Fair Value				(1,286,687)
4	Total (lines 2 and 3)				(733,893)
5	Balance of Account 219 at End of Preceding Quarter/Year				(12,935,653)
6	Balance of Account 219 at Beginning of Current Year				(12,935,653)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				700,421
8	Current Quarter/Year to Date Changes in Fair Value				3,446,092
9	Total (lines 7 and 8)				4,146,513
10	Balance of Account 219 at End of Current Quarter/Year				(8,789,140)

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

Line No.	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 117, Line 78) (i)	Total Comprehensive Income (j)
1	(8,507,014)	(179,474)	(20,888,248)		
2	955,479	652,574	2,160,847		
3	(6,913,864)	(1,293,458)	(9,494,009)		
4	(5,958,385)	(640,884)	(7,333,162)	149,673,884	142,340,722
5	(14,465,399)	(820,358)	(28,221,410)		
6	(14,465,399)	(820,358)	(28,221,410)		
7	595,406	1,359,557	2,655,384		
8	(5,776,935)	(987,335)	(3,318,178)		
9	(5,181,529)	372,222	(662,794)	118,457,416	117,794,622
10	(19,646,928)	(448,136)	(28,884,204)		

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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 Cormmission 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.

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SEE PAGE 123 FOR REQUIRED INFORMATION.

INDEX OF NOTES TO FINANCIAL STATEMENTS

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 or Parent	American Electric Power Company, Inc., an electric utility holding company.
AEP Credit	AEP Credit, Inc., a subsidiary of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP East Companies	APCo, I&M, KPCo and OPCo.
AEP System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEP West Companies	PSO, SWEPCo, TCC and TNC.
AEPES	AEP Energy Services, Inc., a subsidiary of AEP Resources, Inc.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AFUDC	Allowance for Funds Used During Construction.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
CAA	Clean Air Act.
CO_2	Carbon dioxide and other greenhouse gases.
Cook Plant	Donald C. Cook Nuclear Plant, a two-unit, 2,191 MW nuclear plant owned by I&M.
CSW	Central and South West Corporation, a subsidiary of AEP (Effective January 21, 2003, the legal name of Central and South West Corporation was changed to AEP Utilities, Inc.).
CSW Operating Agreement	Agreement, dated January 1, 1997, as amended, by and among PSO and SWEPCo governing generating capacity allocation, energy pricing, and revenues and costs of third party sales. AEPSC acts as the agent.
CWIP	Construction Work in Progress.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company.
FAC	Fuel Adjustment Clause.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FGD	Flue Gas Desulfurization or scrubbers.
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.
Interconnection Agreement	An agreement by and among APCo, I&M, KPCo and OPCo, defining the sharing of costs and benefits associated with their respective generating plants.
IURC	Indiana Utility Regulatory Commission.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.

GLOSSARY OF TERMS FOR NOTES (Continued)

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

Term	Meaning
kV	Kilovolt.
KWh	Kilowatthour.
MISO	Midwest Independent Transmission System Operator.
MLR	Member load ratio, the method used to allocate transactions among members of the Interconnection Agreement.
MMBtu	Million British Thermal Units.
MPSC	Michigan Public Service Commission.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatthour.
NEIL	Nuclear Electric Insurance Limited insures domestic and international nuclear utilities for the costs associated with interruptions, damages, decontaminations and related nuclear risks.
NO_X	Nitrogen oxide.
NSR	New Source Review.
OATT	Open Access Transmission Tariff.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
OTC	Over the counter.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generating plant, consisting of two 1,310 MW coal-fired generating units near Rockport, Indiana, owned by AEGCo and I&M.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
SIA	System Integration Agreement, effective June 15, 2000, provides contractual basis for coordinated planning, operation and maintenance of the power supply sources of the combined AEP.
SNF	Spent Nuclear Fuel.
SO_2	Sulfur dioxide.
SPP	Southwest Power Pool regional transmission organization.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.

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 584,000 retail customers in its service territory in northern and eastern Indiana and a portion of 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 Interconnection Agreement permits the AEP East Companies to pool their generation assets on a cost basis. It establishes an allocation method for generating capacity among its members based on relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity revenues. Members of the Interconnection Agreement are compensated for their costs of energy delivered and charged for energy received. The capacity reserve relationship of the Interconnection Agreement members changes as generating assets are added, retired or sold and relative peak demand changes. The Interconnection Agreement calculates each member's prior twelve-month peak demand relative to the sum of the peak demands of all members as a basis for sharing revenues and costs. The result of this calculation is the MLR, which determines each member's percentage share of revenues and costs. The addition of APCo's Dresden Plant in January 2012 and removal of OPCo's Sporn Plant, Unit 5 in September 2011 changed the capacity reserve relationship of the members.

The AEP East Companies are parties to a Transmission Agreement defining how they share the revenues and costs associated with their relative ownership of transmission assets. This sharing was based upon each company's MLR until the FERC approved a new Transmission Agreement effective November 2010. The new Transmission Agreement will be phased in for retail rates over periods of up to four years, added KGPCo and WPCo as parties to the agreement and changed the allocation method. I&M's recovery mechanism for transmission costs is through its base rates. Changes in allocation under the new Transmission Agreement and state regulatory phase-in of the new agreement will limit I&M's ability to fully recover its transmission costs.

Under a unit power agreement, I&M purchases AEGCo's 50% share of the 2,600 MW Rockport Plant capacity unless it is sold to other utilities. AEGCo is an affiliate that is not a member of the Interconnection Agreement. Another unit power agreement between AEGCo and KPCo provides for the sale of 390 MW of AEGCo's Rockport Plant capacity to KPCo through 2022. Under these agreements, I&M purchases 910 MW of AEGCo's 50% share of Rockport Plant capacity.

Under the SIA, AEPSC allocates physical and financial revenues and expenses from transactions with neighboring utilities, power marketers and other power and gas risk management activities based upon the location of such activity, with margins resulting from trading and marketing activities originating in PJM and MISO generally accruing to the benefit of the AEP East Companies and trading and marketing activities originating in SPP generally accruing to the benefit of PSO and SWEPCo. Margins resulting from other transactions are allocated among the AEP East Companies, PSO and SWEPCo in proportion to the marketing realization directly assigned to each zone for the current month plus the preceding eleven months.

AEPSC conducts power, gas, coal and emission allowance risk management activities on I&M's behalf. I&M shares in the revenues and expenses associated with these risk management activities, as described in the preceding paragraph, with the other AEP East Companies, PSO and SWEPCo. Power and gas risk management activities are allocated based on the Interconnection Agreement and the SIA. I&M shares in coal and emission allowance risk management activities based on its proportion of fossil fuels burned by the AEP System. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and, to a lesser extent, gas, coal and emission allowances. The electricity, gas, coal and emission allowance contracts include physical transactions, OTC options and financially-settled swaps and exchange-traded futures and options. AEPSC settles the majority of the physical forward contracts by entering into offsetting contracts.

To minimize the credit requirements and operating constraints when operating within PJM, the AEP East Companies, as well as KGPCo and WPCo, agreed to a netting of all payment obligations incurred by any of the AEP East Companies against all balances due to the AEP East Companies and to hold PJM harmless from actions that any one or more AEP East Companies may take with respect to PJM.

I&M is jointly and severally liable for activity conducted by AEPSC on behalf of the AEP East Companies related to power purchase and sale activity pursuant to the SIA.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

I&M is subject to regulation by the FERC under the Federal Power Act, the 2005 Public Utility Holding Company Act and the Energy Policy Act of 2005 and maintains accounts in accordance with the FERC and other regulatory guidelines. I&M's rates are regulated by the FERC, the IURC and the MPSC. The FERC also regulates affiliated transactions, including AEPSC intercompany service billings which are generally at cost. The FERC also has jurisdiction over the 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. For non-power goods and services, the FERC requires that a nonregulated affiliate can bill an affiliated public utility company no more than market while a public utility must bill the higher of cost or market to a nonregulated affiliate. 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 I&M negotiates and files a cost-based contract with the FERC or the FERC determines that I&M has "market power" in the region where the transaction occurs. I&M has entered into wholesale power supply contracts 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 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. The FERC claims jurisdiction over retail transmission rates when retail rates are unbundled in connection with restructuring. I&M's retail transmission rates in Michigan are unbundled and are based on formula rates included in the PJM OATT that are cost-based. In Indiana, bundled retail transmission rates are regulated, on a cost basis, by the IURC.

In addition, the FERC regulates the SIA, the Interconnection Agreement, the CSW Operating Agreement, the System Transmission Integration Agreement, the Transmission Agreement, the Transmission Coordination Agreement and the AEP System Interim Allowance Agreement, all of which allocate shared system costs and revenues to the AEP East Companies, PSO and SWEPCo that are parties to each agreement. In October 2012, the AEP East Companies asked the FERC to terminate the existing Interconnection Agreement and the AEP System Interim Allowance Agreement and approve a new Power Coordination Agreement among APCo, I&M and KPCo. A decision is expected from the FERC in mid-2013.

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 accounting principles generally accepted in the United States of America (GAAP) include:

- Accounting for subsidiaries on an equity basis.
- The classification of deferred fuel as noncurrent rather than current.
- The classification of interest on deferred fuel as interest accrued rather than deferred fuel.
- 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 capital lease payments as operating activities instead of financing activities.
- The classification of change in emission allowances held for speculation as investing activities instead of operating 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 tax assets related to the accounting guidance for "Uncertainty in Income Taxes" as a reduction to current liabilities rather than a tax benefit.
- The classification of noncurrent tax liabilities related to the accounting guidance for "Uncertainty in Income Taxes" as a current liability rather than a noncurrent 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 capital 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 expenses.
- 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 coal procurement sales as a reduction of fuel expense rather than as revenue.
- 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 certain other assets and liabilities as current instead of noncurrent.
- The classification of certain other assets and liabilities as noncurrent instead of current.

Accounting for the Effects of Cost-Based Regulation

As a rate-regulated electric public utility company, 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," I&M records regulatory assets (deferred expenses) and regulatory liabilities (deferred revenue reductions or refunds) to reflect the economic effects of regulation in the same accounting period by matching expenses with its 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 doubtful accounts, 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 on the statements of cash flows include Cash, Working Fund and Temporary Cash Investments on the balance sheets with original maturities of three months or less.

Supplementary Information

	2012	2011
For the Years Ended December 31,	**(in thousands)**	
Cash was Paid (Received) for:		
Interest (Net of Capitalized Amounts)	$ 91,448	$ 88,492
Income Taxes (Net of Refunds)	(15,117)	(96,524)
Noncash Acquisitions Under Capital Leases	115,743	113,429
As of December 31,		
Construction Expenditures Included in Current and Accrued Liabilities	112,622	42,992
Acquisition of Nuclear Fuel Included in Current and Accrued Liabilities	35,493	715
Noncash Increase in Long-term Debt Through the Fort Wayne Lease Settlement	-	26,802
Expected Reimbursement for SNF Dry Cask Storage	30,332	-

Special Deposits

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

Inventory

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

Accounts Receivable

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 from electric power sales when power is delivered to customers. To the extent that deliveries have occurred but a bill has not been issued, I&M accrues and recognizes, as Accrued Utility Revenues, 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.

Allowance for Uncollectible Accounts

Generally, AEP Credit records bad debt expense related to receivables purchased from I&M under a sale of receivables agreement. For customer accounts receivables relating to risk management activities, accounts receivables are reviewed for bad debt reserves at a specific counterparty level basis. For miscellaneous accounts receivable, bad debt expense is recorded for all amounts outstanding 180 days or greater at 100%, unless specifically identified. Miscellaneous accounts receivable items open less than 180 days may be reserved using specific identification for bad debt reserves.

Concentrations of Credit Risk and Significant Customers

I&M does not have any significant customers that comprise 10% or more of its Operating Revenues as of December 31, 2012.

I&M monitors credit levels and the financial condition of its customers on a continuing 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 financial statements.

Emission Allowances

I&M records emission allowances at cost, including the annual SO_2 and NO_X emission allowance entitlements received at no cost from the Federal EPA. Allowances are consumed in the production of energy and are recorded in Operation Expenses at an average cost. The purchases and sales of allowances are reported in the Operating Activities section of the statements of cash flows.

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 the original cost, 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 salvage received. These rates and the related lives are subject to periodic review. Removal costs are charged to accumulated depreciation. The costs of labor, materials and overhead incurred to operate and maintain plants are included in operating expenses.

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 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, the cost of that asset shall be removed from plant-in-service or CWIP and charged to expense.

The fair value of an asset or investment is the amount at which that asset or investment 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 or investments 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)

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.

Valuation of Nonderivative Financial Instruments

The book values of Cash, Special Deposits, Working Fund, accounts receivable and accounts payable approximate fair value because of the short-term maturity of these instruments. The book value of the pre-April 1983 spent nuclear fuel disposal liability approximates the best estimate of its fair value.

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. The AEP System's market risk oversight staff independently monitors its valuation policies and procedures and provides members of the Commercial Operations Risk Committee (CORC) various daily, weekly and monthly reports, regarding compliance with policies and procedures. The CORC consists of AEPSC's Chief Operating Officer, Chief Financial Officer, Executive Vice President of Energy Supply, Senior Vice President of Commercial Operations and Chief Risk Officer.

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 contracts 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 and 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 significant portion of the Level 3 instruments have been economically hedged which greatly 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. The trustee uses multiple pricing vendors for the assets held in the trusts.

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 domestic 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 and cash equivalents funds. Fixed income securities do not trade on an exchange 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. Benefit plan assets included in Level 3 are primarily real estate and private equity investments that are valued using methods requiring judgment including appraisals.

Deferred Fuel Costs

The cost of fuel and related emission allowances and emission control chemicals/consumables is charged to expense 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 on the units-of-production method. In regulated jurisdictions with an active FAC, fuel cost over-recoveries (the excess of fuel revenues billed to customers over applicable fuel costs incurred) are generally deferred as regulatory liabilities and under-recoveries (the excess of applicable fuel costs incurred over fuel revenues billed to customers) are generally deferred as regulatory assets. These deferrals are amortized when refunded or when billed to customers in later months with the state regulatory commissions' review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of the state regulatory commissions. 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. When a fuel cost disallowance becomes probable, I&M adjusts its FAC deferrals and record provisions for estimated refunds to recognize these probable outcomes.

Changes in fuel costs, including purchased power are reflected in rates in a timely manner generally through the FAC. The FAC generally includes some sharing of off-system sales. A portion of profits from off-system sales are given to customers through the FAC and other rate mechanisms in Indiana and Michigan.

Revenue Recognition

Regulatory Accounting

The 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) 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.

When regulatory assets are probable of recovery through regulated rates, I&M records them as assets on the balance sheets. I&M tests 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, I&M writes off that regulatory asset as a charge against income.

Electricity Supply and Delivery Activities

I&M recognizes revenues from retail and wholesale electricity sales and electricity transmission and distribution delivery services. I&M recognizes the revenues on the statements of income upon delivery of the energy to the customer and include unbilled as well as billed amounts.

Most of the power produced at the generation plants of the AEP East Companies is sold to PJM, the RTO operating in the east service territory. The AEP East Companies purchase power from PJM to supply power to their customers. Generally, these power sales and purchases are reported on a net basis as revenues. 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. Other RTOs do not function in the same manner as PJM. They function as balancing organizations and not as exchanges.

Physical energy purchases arising from non-derivative contracts are accounted for on a gross basis in Operation Expenses. Energy purchases arising from non-trading derivative contracts are recorded based on the transaction's economic substance. Purchases under non-trading derivatives used to serve accrual based obligations are recorded in Operation Expenses. 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, with the exception of certain power purchase contracts that are derivatives and accounted for using MTM accounting. The unrealized MTM amounts are deferred as regulatory assets (for losses) and regulatory liabilities (for gains).

Energy Marketing and Risk Management Activities

AEPSC, on behalf of I&M, engages in wholesale electricity, coal, natural gas and emission allowances marketing and risk management activities focused on wholesale markets where the AEP System owns assets and 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 and expenses from wholesale marketing and risk management transactions that are not derivatives upon delivery of the commodity. I&M uses MTM accounting for wholesale marketing and risk management transactions that are derivatives unless the derivative is designated in a qualifying cash flow hedge relationship or a normal purchase or sale. I&M includes realized gains and losses on wholesale marketing and risk management transactions in revenues on a net basis. The unrealized MTM amounts and some realized gains and losses are deferred as regulatory assets (for losses) and regulatory liabilities (for gains).

Certain qualifying wholesale 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). I&M initially records the effective portion of the cash flow hedge's gain or loss 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 its statements of income. I&M defers the ineffective portion as regulatory assets (for losses) and regulatory liabilities (for gains). See "Accounting for Cash Flow Hedging Strategies" section of Note 7.

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 the period 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. I&M adjusts the amortization amount as necessary to ensure full amortization of all deferred costs by the end of the refueling cycle.

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 their recovery in cost-based regulated revenues.

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.

When the flow-through method of accounting for temporary differences is 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.

Investment tax credits are accounted for under the flow-through method except where regulatory commissions have reflected investment tax credits in the rate-making process on a deferral basis. Investment tax credits that have been deferred are amortized over the life of the plant investment.

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.

Excise Taxes

As agents 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 plants 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.

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 spent nuclear fuel disposal. All of the trust funds' investments are diversified and managed in compliance with all laws and regulations. The investment strategy for trust funds is to use a diversified portfolio of investments to achieve an acceptable rate of return while managing the interest rate sensitivity 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 investment policy for the pension fund allocates assets based on the funded status of the pension plan. The objective of the asset allocation policy is to reduce the investment volatility of the plan over time. Generally, more of the investment mix will be allocated to fixed income investments as the plan becomes better funded. Assets will be transferred away from equity investments into fixed income investments based on the market value of plan assets compared to the plan's projected benefit obligation. The current target asset allocations are as follows:

Pension Plan Assets	Target
Equity	40.0 %
Fixed Income	50.0 %
Other Investments	10.0 %

OPEB Plans Assets	Target
Equity	66.0 %
Fixed Income	33.0 %
Cash	1.0 %

The investment policy for each benefit plan contains various investment limitations. The investment policies establish concentration limits for securities. Investment policies prohibit the benefit trust funds from purchasing securities issued by AEP (with the exception of proportionate and immaterial holdings of AEP securities in passive index strategies). 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. Each investment manager's portfolio is compared to a diversified benchmark index.

For equity investments, the limits are as follows:

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

For fixed income investments, the concentration limits must not exceed:

- 3% in any single issuer
- 5% for private placements
- 5% for convertible securities
- 60% for bonds rated AA+ or lower
- 50% for bonds rated A+ or lower
- 10% for bonds rated BBB- or lower

For obligations of non-government issuers, the following limitations apply:

- AAA rated debt: a single issuer should account for no more than 5% of the portfolio.
- AA+, AA, AA- rated debt: a single issuer should account for no more than 3% of the portfolio.
- Debt rated A+ or lower: a single issuer should account for no more than 2% of the portfolio.
- No more than 10% of the portfolio may be invested in high yield and emerging market debt combined at any time.

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 development risk classifications and some investments in Real Estate Investment Trusts (REITs), which are publicly traded real estate securities classified as Level 1.

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 and commingled funds 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 investment instruments. Commingled private equity funds are used to enhance the holdings' diversity.

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 cash collateral. All loans are collateralized by at least 102% of the loaned asset's market value and the cash collateral is invested. The difference between the rebate owed to the borrower and the cash collateral rate of return determines the earnings on the loaned security. The securities lending program's objective is providing modest incremental income with a limited increase in risk.

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 (VEBA) 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. The cash funds are valued each business day and provide daily liquidity.

Nuclear Trust Funds

Nuclear decommissioning and spent nuclear fuel trust funds represent funds that regulatory commissions allow I&M to collect through rates to fund future decommissioning and spent nuclear fuel 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. The trust assets may not be used for another jurisdiction's liabilities. Regulatory approval is required to withdraw decommissioning funds. These funds are managed by external investment managers who 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. I&M records these securities at fair value. I&M classifies securities in the trust funds as available-for-sale due to their long-term purpose. Other-than-temporary impairments for investments in both debt and equity 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 equity and debt 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 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 4 for additional discussion of nuclear matters. See "Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal" section of Note 8 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 nonowner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners.

2. RATE MATTERS

I&M is involved in rate and regulatory proceedings at the FERC and 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.

2011 Indiana Base Rate Case

In September 2011, I&M filed a request with the IURC for a net annual increase in Indiana base rates of $149 million based upon a return on common equity of 11.15%. The $149 million net annual increase reflects an increase in base rates of $178 million offset by proposed corresponding reductions of $13 million to the off-system sales sharing rider, $9 million to the PJM cost rider and $7 million to the clean coal technology rider rates. The request included an increase in depreciation rates that would result in an increase of approximately $25 million in annual depreciation expense. Included in the depreciation rates increase was a decrease in the average remaining life of Tanners Creek Plant to account for the change in the retirement date of Tanners Creek Plant, Units 1-3 from 2020 to 2014. In May 2012, I&M filed rebuttal testimony which changed the retirement date for Tanners Creek Plant, Units 1-3 to 2015 and supported an increase of $170 million in base rates, excluding reductions to certain riders.

In February 2013, the IURC issued an order that granted an $85 million annual increase in base rates based upon a return on common equity of 10.2%, effective March 2013. The $85 million annual increase in base rates will be offset by corresponding reductions of $5 million to the off-system sales sharing rider, $11 million to the PJM cost rider and $7 million to the clean coal technology rider rates. The IURC granted the requested increase in depreciation rates, modified the shareholder's portion of off-system sales margins to 50% below and above the $27 million imbedded in base rates, established a capacity tracker and established a major storm damage restoration reserve.

Cook Plant Life Cycle Management Project

In April and May 2012, I&M filed a petition with the IURC and the MPSC, respectively, for approval of the Cook Plant Life Cycle Management Project (LCM Project), which consists of a group of capital projects to ensure the safe and reliable operations of the Cook Plant through its licensed life. The estimated cost of the LCM Project is $1.2 billion to be incurred through 2018, excluding AFUDC.

In Indiana, I&M requested recovery of certain project costs, including interest, through a new rider effective January 2013. In Michigan, I&M requested that the MPSC approve a Certificate of Need and authorize I&M to defer, on an interim basis, incremental depreciation and related property tax costs, including interest, along with study, analysis and development costs until the applicable LCM costs are included in I&M's base rates. As of December 31, 2012, I&M has incurred $176 million related to the LCM Project, including AFUDC.

In August 2012, intervenors filed testimony in Indiana. The Indiana Michigan Power Company Industrial Group recommended that I&M recover $229 million in a rider with the remaining costs to be requested in future base rate cases. The Indiana Office of Utility Consumer Counselor (OUCC) recommended a maximum of $408 million of LCM project costs be recovered in a rider, and a maximum of $299 million for projects the OUCC believes are not related to LCM to be recovered in future base rates. The IURC held a hearing in January 2013.

In January 2013, the MPSC approved a Certificate of Need (CON) for the LCM Project with total costs of $851 million (Michigan jurisdictional share is approximately 15%) for the period 2013 through 2018. The order provided that depreciation, property taxes and a return using the overall rate of return approved in I&M's last Michigan base rate case related to the 2013 through 2018 LCM Project costs can be deferred until these costs are included in rates. The order excluded from the CON $176 million of LCM costs spent prior to 2013 as $39 million was included in the determination of Michigan base rates, effective April 2012, and the remaining $137 million in CWIP will be requested in a future base rate case. The order also excluded $142 million of future LCM costs, which if incurred, will be requested in a future base rate case. Under Michigan law, the approved CON amount is eligible for a cost increase allowance of 10%, up to $85 million, of the approved project costs in the event project costs exceed the approved level of costs.

If I&M is not ultimately permitted to recover its LCM Project costs, it would reduce future net income and cash flows and impact financial condition.

Rockport Plant Environmental Controls

I&M filed an application with the IURC seeking approval of a Certificate of Public Convenience and Necessity (CPCN) to retrofit one unit at the Rockport Plant with environmental controls estimated to cost $1.4 billion to comply with new requirements. AEGCo and I&M jointly own Unit 1 and jointly lease Unit 2 of the Rockport Plant. I&M is also evaluating options related to the maturity of the lease for Rockport Plant Unit, 2 in 2022 and continues to investigate alternative compliance technologies for these units as part of its overall compliance strategy. As of December 31, 2012, I&M has incurred $36 million related to these environmental controls, including AFUDC. If I&M is not ultimately permitted to recover its incurred costs, it would reduce future net income and cash flows.

In February 2013, I&M filed a motion with the IURC to dismiss its request for approval of a CPCN for environmental controls after modification to the NSR consent decree. Under the terms of the NSR consent decree modification, the units of Rockport Plant will be equipped with dry sorbent injection systems in 2015 and have options to retrofit additional SO_2 controls, refuel, repower or retire in 2025 and 2028.

Seams Elimination Cost Allocation (SECA) Revenue Subject to Refund

In 2004, AEP eliminated transaction-based through-and-out transmission service charges and collected, at the FERC's direction, load-based charges, referred to as RTO SECA through March 2006. Intervenors objected and the FERC set SECA rate issues for hearing and ordered that the SECA rate revenues be collected, subject to refund. The AEP East Companies recognized gross SECA revenues of $220 million. I&M's portion of recognized gross SECA revenues is $41.3 million.

In 2006, a FERC Administrative Law Judge issued an initial decision finding that the SECA rates charged were unfair, unjust and discriminatory and that new compliance filings and refunds should be made.

AEP filed briefs jointly with other affected companies asking the FERC to reverse the decision. In May 2010, the FERC issued an order that generally supported AEP's position and required a compliance filing. In August 2010, the affected companies, including the AEP East Companies, filed a compliance filing with the FERC. The AEP East Companies provided reserves for net refunds for SECA settlements. The AEP East Companies settled with various parties prior to the FERC compliance filing and entered into additional settlements subsequent to the compliance filing being filed at the FERC. Based on the analysis of the May 2010 order, the compliance filing and recent settlements, management believes that the reserve is adequate to pay the refunds, including interest, and any remaining exposure beyond the reserve is immaterial.

Termination of Interconnection Agreement

In October 2012, the AEP East Companies submitted several filings with the FERC. The AEP East Companies asked the FERC to terminate the existing Interconnection Agreement and approve a Power Coordination Agreement among APCo, I&M and KPCo. Intervenors have opposed several of these filings. The AEP East Companies have responded and continue to pursue approvals from the FERC. A decision from the FERC is expected in mid-2013.

If I&M experiences a decrease in revenues or an increase in expenses as a result of changes to its relationship with affiliates and is unable to recover the change in revenues and costs through rates, prices or additional sales, it could reduce future net income and cash flows.

3. EFFECTS OF REGULATION

Regulatory assets and liabilities are comprised of the following items:

Regulatory Assets:	December 31, 2012	2011	Remaining Recovery Period
	(in thousands)		
Regulatory assets not yet being recovered pending future proceedings to determine the recovery method and timing:			
Regulatory Assets Currently Not Earning a Return			
Mountaineer Carbon Capture and Storage Commercial Scale Facility	$ 1,380	$ 1,680	
Litigation Settlement	11,098	10,803	
Other Regulatory Assets Not Yet Being Recovered	786	-	
Total Regulatory Assets Not Yet Being Recovered	13,264	12,483	
Regulatory assets being recovered:			
Regulatory Assets Currently Earning a Return			
Unamortized Loss on Reacquired Debt	2,070	2,276	10 years
RTO Formation/Integration Costs	3,229	3,858	7 years
Under-recovered Fuel Costs	3,037	95	1 year
Customer Choice Implementation Costs	1,493	4,680	1 year
Regulatory Assets Currently Not Earning a Return			
Income Tax Assets	253,148	222,020	36 years
Pension and OPEB Funded Status	220,797	291,392	12 years
Postemployment Benefits	8,897	9,137	5 years
Deferred Restructuring Costs	3,688	4,952	3 years
Asset Retirement Obligation	808	3,396	8 years
Cook Nuclear Plant Refueling Outage Levelization	26,652	40,551	3 years
Under-recovered Fuel Costs	1,772	8,876	1 year
Deferred PJM Fees	13,998	21,746	2 years
River Transportation Division Expenses	4,576	1,899	1 year
Peak Demand Reduction/Energy Efficiency	2,608	1,387	1 year
Other Regulatory Assets Being Recovered	1,886	1,395	various
Total Regulatory Assets Being Recovered	548,659	617,660	
Total FERC Account 182.3 Regulatory Assets	$ 561,923	$ 630,143	

Regulatory Liabilities:	December 31, 2012	December 31, 2011	Remaining Refund Period
	(in thousands)		
Regulatory liabilities not yet being paid:			
Regulatory Liabilities Currently Paying a Return			
Other Regulatory Liabilities Not Yet Being Paid	$ -	$ 318	
Regulatory Liabilities Currently Not Paying a Return			
Other Regulatory Liabilities Not Yet Being Paid	124	136	
Total Regulatory Liabilities Not Yet Being Paid	124	454	
Regulatory liabilities being paid:			
Regulatory Liabilities Currently Not Paying a Return			
Income Tax Liabilities	30,896	33,271	36 years
Unrealized Gain on Forward Commitments	19,872	21,785	5 years
Peak Demand Reduction/Energy Efficiency	11,080	11,078	1 year
Excess Asset Retirement Obligations for Nuclear Decommissioning Liability	435,717	377,162	(a)
Spent Nuclear Fuel Liability	42,898	42,603	(a)
Off-system Sales Margin Sharing	7,611	5,892	1 year
Indiana Clean Coal Technology Rider	774	1,242	1 year
Other Regulatory Liabilities Being Paid	1,077	198	various
Total Regulatory Liabilities Being Paid	549,925	493,231	
Total FERC Account 254 Regulatory Liabilities	$ 550,049	$ 493,685	

(a) Relieved when plant is decommissioned.

4. COMMITMENTS, GUARANTEES AND CONTINGENCIES

I&M is subject to certain claims and legal actions arising in its 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. 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

Construction and Commitments

I&M has substantial construction commitments to support its operations and environmental investments. In managing the overall construction program and in the normal course of business, I&M contractually commits to third-party construction vendors for certain material purchases and other construction services. Management forecasts approximately $484 million of construction expenditures, excluding equity AFUDC and capitalized interest for 2013. I&M also purchases fuel, materials, supplies, services and property, plant and equipment under contract as part of its normal course of business. Certain supply contracts contain penalty provisions for early termination.

The following table summarizes the actual contractual commitments as of December 31, 2012:

Contractual Commitments	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in thousands)		
Fuel Purchase Contracts (a)	$ 330,157	$ 535,223	$ 336,830	$ 447,930	$ 1,650,140
Energy and Capacity Purchase Contracts (b)	89,128	178,501	178,543	609,371	1,055,543
Construction Contracts for Capital Assets (c)	6,389	-	-	-	6,389
Total	$ 425,674	$ 713,724	$ 515,373	$ 1,057,301	$ 2,712,072

(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.
(b) Represents contractual commitments for energy and capacity purchase contracts.
(c) Represents only capital assets for which there are signed contracts. Actual payments are dependent upon and may vary significantly based upon the decision to build, regulatory approval schedules, timing and escalation of projects costs.

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.

Letters of Credit

I&M enters into standby letters of credit with third parties. These letters of credit are issued in the ordinary course of business and cover items such as insurance programs, security deposits and debt service reserves.

AEP has two credit facilities totaling $3.25 billion, under which up to $1.35 billion may be issued as letters of credit. In February 2013, AEP increased and extended the $1.5 billion credit facility due in June 2015 to $1.75 billion due in June 2016 and extended the $1.75 billion credit facility due in July 2016 to July 2017. As of December 31, 2012, I&M's maximum future payment for letters of credit issued under the credit facilities was $150 thousand with a maturity of March 2013.

I&M has $77 million of variable rate Pollution Control Bonds supported by bilateral letters of credit for $77.9 million. In February 2013, I&M extended its bilateral letters of credit due in March 2013 to March 2015.

Indemnifications and Other Guarantees

Contracts

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, 2012, there were no material liabilities recorded for any indemnifications.

I&M are jointly and severally liable for activity conducted by AEPSC on behalf of the AEP East Companies related to power purchase and sale activity pursuant to the SIA.

Lease Obligations

I&M leases certain equipment under master lease agreements. See “Master Lease Agreements” and “Railcar Lease” sections of Note 10 for disclosure of lease residual value guarantees.

ENVIRONMENTAL CONTINGENCIES

Carbon Dioxide Public Nuisance Claims

In October 2009, the Fifth Circuit Court of Appeals reversed a decision by the Federal District Court for the District of Mississippi dismissing state common law nuisance claims in a putative class action by Mississippi residents asserting that CO_2 emissions exacerbated the effects of Hurricane Katrina. The Fifth Circuit held that there was no exclusive commitment of the common law issues raised in plaintiffs’ complaint to a coordinate branch of government and that no initial policy determination was required to adjudicate these claims. The court granted petitions for rehearing. An additional recusal left the Fifth Circuit without a quorum to reconsider the decision and the appeal was dismissed, leaving the district court’s decision in place. Plaintiffs filed a petition with the U.S. Supreme Court asking the court to remand the case to the Fifth Circuit and reinstate the panel decision. The petition was denied in January 2011. Plaintiffs refiled their complaint in federal district court. The court ordered all defendants to respond to the refiled complaints in October 2011. In March 2012, the court granted the defendants’ motion for dismissal on several grounds, including the doctrine of collateral estoppel and the applicable statute of limitations. Plaintiffs appealed the decision to the Fifth Circuit Court of Appeals. Management will continue to defend against the claims. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

Alaskan Villages' Claims

In 2008, the Native Village of Kivalina and the City of Kivalina, Alaska filed a lawsuit in Federal Court in the Northern District of California against AEP, AEPSC and 22 other unrelated defendants including oil and gas companies, a coal company and other electric generating companies. The complaint alleges that the defendants' emissions of CO_2 contribute to global warming and constitute a public and private nuisance and that the defendants are acting together. The complaint further alleges that some of the defendants, including AEP, conspired to create a false scientific debate about global warming in order to deceive the public and perpetuate the alleged nuisance. The plaintiffs also allege that the effects of global warming will require the relocation of the village at an alleged cost of $95 million to $400 million. In October 2009, the judge dismissed plaintiffs' federal common law claim for nuisance, finding the claim barred by the political question doctrine and by plaintiffs' lack of standing to bring the claim. The judge also dismissed plaintiffs' state law claims without prejudice to refiling in state court. The plaintiffs appealed the decision. In September 2012, the Ninth Circuit Court of Appeals affirmed the trial court's decision, holding that the CAA displaced Kivalina's claims for damages. Plaintiffs' petition for rehearing by the full court was denied in November 2012, but the plaintiffs could seek further review in the U.S. Supreme Court. Management believes the action is without merit and will continue to defend against the claims. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

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 generating plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls and other hazardous and nonhazardous materials. I&M currently incurs costs to dispose of these substances safely.

Superfund addresses clean-up of hazardous substances that have been released to the environment. The Federal EPA administers the clean-up programs. Several states have enacted similar laws. As of December 31, 2012, there is one site for which I&M has received an information request which could lead to Potentially Responsible Party (PRP) designation. I&M has also been named potentially liable at two sites under state law including the I&M site discussed in the next paragraph. In those instances where I&M has been named a PRP or defendant, 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.

In 2008, I&M received a letter from the Michigan Department of Environmental Quality (MDEQ) concerning conditions at a site under state law and requesting I&M take voluntary action necessary to prevent and/or mitigate public harm. I&M started remediation work in accordance with a plan approved by MDEQ. I&M's reserve is approximately $10 million. As the remediation work is completed, I&M's cost may change as new information becomes available concerning either the level of contamination at the site or changes in the scope of remediation required by the MDEQ. Management cannot predict the amount of additional cost, if any.

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 nonhazardous. 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. At present, management's estimates do not anticipate material cleanup costs for identified Superfund sites, except the site discussed above.

NUCLEAR CONTINGENCIES

I&M owns and operates the two-unit 2,191 MW Cook Plant under licenses granted by the Nuclear Regulatory Commission (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. 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 generating 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 liability could be substantial.

Decommissioning and Low Level Waste Accumulation Disposal

The cost to decommission a nuclear plant is affected by NRC regulations and the SNF disposal program. Decommissioning costs are accrued over the service life of the Cook Plant. The most recent decommissioning cost study was performed in 2012. According to that study, the estimated cost of decommissioning and disposal of low-level radioactive waste ranges from $1.3 billion to $1.7 billion in 2012 nondiscounted dollars. The wide range in estimated costs is caused by variables in assumptions. I&M recovers estimated decommissioning costs for the Cook Plant in its rates. The amounts recovered in rates were $14 million and $14 million for the years ended December 31, 2012 and 2011, respectively. Decommissioning costs recovered from customers are deposited in external trusts.

As of December 31, 2012 and 2011, the total decommissioning trust fund balance was $1.4 billion and $1.3 billion, respectively. Trust fund earnings increase the fund assets and decrease the amount remaining to be recovered from ratepayers. The decommissioning costs (including interest, unrealized gains and losses and expenses of the trust funds) increase or decrease the recorded liability.

I&M continues to work with regulators and customers to recover the remaining 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 continues to increase and cannot be recovered.

SNF 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 is being collected from customers and remitted to the U.S. Treasury. As of December 31, 2012 and 2011, fees and related interest of $265 million and $265 million, respectively, for fuel consumed prior to April 7, 1983 have been recorded as Other Long-term Debt and funds collected from customers along with related earnings totaling $308 million and $308 million, respectively, to pay the fee are recorded as part of Other Special Funds. 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 delays in accepting SNF for permanent storage. Under the settlement agreement, I&M received $20 million and $14 million in 2012 and 2011, respectively, to recover costs and will be eligible to receive additional payment of annual claims for allowed costs that are incurred through December 31, 2013. The proceeds reduced costs for dry cask storage. As of December 31, 2012, I&M has deferred $45 million in Miscellaneous Current and Accrued Assets of 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 8 for disclosure of the fair value of assets within the trusts.

Nuclear Incident Liability

I&M carries insurance coverage for property damage, decommissioning and decontamination at the Cook Plant in the amount of $1.8 billion. I&M purchases $1 billion of excess coverage for property damage, decommissioning and decontamination. Additional insurance provides coverage for a weekly indemnity payment resulting from an insured accidental outage. I&M utilizes an industry mutual insurer for the placement of this insurance coverage. Participation in this mutual insurance requires a contingent financial obligation of up to $40 million for I&M which is assessable if the insurer's financial resources would be inadequate to pay for losses.

The Price-Anderson Act, extended through December 31, 2025, establishes insurance protection for public liability arising from a nuclear incident at $12.6 billion and covers any incident at a licensed reactor in the U.S. Commercially available insurance, which must be carried for each licensed reactor, provides $375 million of 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 $117.5 million on each licensed reactor in the U.S. payable in annual installments of $17.5 million. As a result, I&M could be assessed $235 million per nuclear incident payable in annual installments of $35 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 initially covered for the first $375 million through commercially available insurance. The next level of liability coverage of up to $12.2 billion would be covered by claims made under the Price-Anderson Act. If the liability were in excess of amounts recoverable from insurance and retrospective claim payments made under the Price-Anderson Act, I&M would seek to recover those amounts from customers through rate increases. In the event nuclear losses or liabilities are underinsured or exceed accumulated funds and recovery from customers is not possible, it could reduce future net income and cash flows and impact financial condition.

Cook Plant, Unit 1 Fire and Shutdown

In September 2008, I&M shut down Cook Plant, Unit 1 (Unit 1) due to turbine vibrations, caused by blade failure, which resulted in significant turbine damage and a small fire on the electric generator. This equipment, located in the turbine building, is separate and isolated from the nuclear reactor. The turbine rotors that caused the vibration were installed in 2006 and are within the vendor's warranty period. The warranty provides for the repair or replacement of the turbine rotors if the damage was caused by a defect in materials or workmanship. Repair of the property damage and replacement of the turbine rotors and other equipment cost approximately $400 million. Due to the extensive lead time required to manufacture and install new turbine rotors, I&M repaired Unit 1 and it resumed operations in December 2009 at slightly reduced power. The installation of the new turbine rotors and other equipment occurred as planned during the fall 2011 refueling outage of Unit 1.

I&M maintains insurance through NEIL. In February 2013, management signed an agreement and received payment from NEIL to settle the remaining insurance claims. The settlement did not have a material impact on net income, cash flows or financial condition.

OPERATIONAL CONTINGENCIES

Insurance and Potential Losses

I&M maintains insurance coverage normal and customary for electric utilities, subject to various deductibles. 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 of this footnote for a discussion of I&M's nuclear exposures and related insurance.

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 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 from customers, could reduce future net income and cash flows and impact financial condition.

5. BENEFIT PLANS

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

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

I&M recognizes the funded status associated with defined benefit pension and OPEB plans in its 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 recognizes, 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 ratemaking 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 as of December 31 of each year used in the measurement of benefit obligations are shown in the following table:

	Pension Plans		Other Postretirement Benefit Plans	
Assumptions	**2012**	**2011**	**2012**	**2011**
Discount Rate	3.95 %	4.55 %	3.95 %	4.75 %
Rate of Compensation Increase	5.00 % (a)	4.75 % (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 2012, the rate of compensation increase assumed varies with the age of the employee, ranging from 3.5% per year to 11.5% per year, with an average increase of 5%.

Actuarial Assumptions for Net Periodic Benefit Costs

The weighted-average assumptions as of January 1 of each year used in the measurement of benefit costs are shown in the following table:

Assumptions	Pension Plans 2012	Pension Plans 2011	Other Postretirement Benefit Plans 2012	Other Postretirement Benefit Plans 2011
Discount Rate	4.55 %	5.05 %	4.75 %	5.25 %
Expected Return on Plan Assets	7.25 %	7.75 %	7.25 %	7.50 %
Rate of Compensation Increase	5.00 %	4.75 %	NA	NA

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 and current prospects for economic growth.

The health care trend rate assumptions as of January 1 of each year used for OPEB plans measurement purposes are shown below:

Health Care Trend Rates	2012	2011
Initial	7.00 %	7.50 %
Ultimate	5.00 %	5.00 %
Year Ultimate Reached	2020	2016

Assumed health care cost trend rates have a significant effect on the amounts reported for the OPEB health care plans. A 1% change in assumed health care cost trend rates would have the following effects:

	1% Increase	1% Decrease
	(in thousands)	
Effect on Total Service and Interest Cost Components of Net Periodic Postretirement Health Care Benefit Cost	$ 2,973	$ (2,357)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	11,682	(8,821)

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, 2012, 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 and Funded Status as of December 31, 2012 and 2011

The following table provides a reconciliation of the changes in the plans' benefit obligations, fair value of plan assets and funded status as of December 31. The benefit obligation for the defined benefit pension and OPEB plans are the projected benefit obligation and the accumulated benefit obligation, respectively.

	Pension Plans		Other Postretirement Benefit Plans	
	2012	**2011**	**2012**	**2011**
Change in Benefit Obligation		**(in thousands)**		
Benefit Obligation as of January 1	$ 581,249	$ 560,553	$ 273,011	$ 262,931
Service Cost	9,908	9,447	6,621	6,119
Interest Cost	26,227	27,706	12,590	13,404
Actuarial Loss	44,922	17,310	13,145	28,139
Plan Amendment Prior Service Credit	-	-	(78,851)	(24,845)
Benefit Payments	(43,332)	(33,767)	(18,132)	(17,960)
Participant Contributions	-	-	4,226	4,112
Medicare Subsidy	-	-	1,160	1,111
Benefit Obligation as of December 31	$ 618,974	$ 581,249	$ 213,770	$ 273,011
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1	$ 503,471	$ 451,242	$ 181,237	$ 188,690
Actual Gain (Loss) on Plan Assets	69,167	32,769	14,357	(3,946)
Company Contributions	22,296	53,227	12,440	10,341
Participant Contributions	-	-	4,226	4,112
Benefit Payments	(43,332)	(33,767)	(18,132)	(17,960)
Fair Value of Plan Assets as of December 31	$ 551,602	$ 503,471	$ 194,128	$ 181,237
Underfunded Status as of December 31	$ (67,372)	$ (77,778)	$ (19,642)	$ (91,774)

Amounts Recognized on the Balance Sheets as of December 31, 2012 and 2011

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2012	2011	2012	2011
	(in thousands)			
Miscellaneous Current and Accrued Liabilities - Short-term Benefit Liability	$ (15)	$ (57)	$ -	$ -
Accumulated Provision for Pensions and Benefits - Long-term Benefit Liability	(67,357)	(77,721)	(19,642)	(91,774)
Underfunded Status	$ (67,372)	$ (77,778)	$ (19,642)	$ (91,774)

Amounts Included in AOCI and Regulatory Assets as of December 31, 2012 and 2011

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2012	2011	2012	2011
Components	(in thousands)			
Net Actuarial Loss	$ 211,477	$ 215,746	$ 123,560	$ 119,224
Prior Service Cost (Credit)	901	1,307	(103,959)	(27,491)
Recorded as				
Regulatory Assets	$ 202,821	$ 207,237	$ 17,976	$ 84,155
Deferred Income Taxes	3,345	3,435	569	2,653
Net of Tax AOCI	6,212	6,381	1,056	4,925

Components of the change in amounts included in AOCI and regulatory assets during the years ended December 31, 2012 and 2011 are as follows:

	Pension Plans		Other Postretirement Benefit Plans	
	Years Ended December 31,			
	2012	2011	2012	2011
Components	(in thousands)			
Actuarial Loss During the Year	$ 13,289	$ 21,360	$ 11,254	$ 45,584
Prior Service Credit	-	-	(78,851)	(24,845)
Amortization of Actuarial Loss	(17,558)	(14,134)	(6,918)	(3,442)
Amortization of Prior Service Credit (Cost)	(406)	(743)	2,383	236
Change for the Year	$ (4,675)	$ 6,483	$ (72,132)	$ 17,533

Pension and Other Postretirement Plans' Assets

The following table presents the classification of pension plan assets within the fair value hierarchy as of December 31, 2012:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 153,658	$ -	$ -	$ -	$ 153,658	27.9 %
International	58,355	-	-	-	58,355	10.5 %
Real Estate Investment Trusts	10,637	-	-	-	10,637	1.9 %
Common Collective Trust - International	-	510	-	-	510	0.1 %
Subtotal - Equities	222,650	510	-	-	223,160	40.4 %
Fixed Income:						
Common Collective Trust - Debt	-	3,727	-	-	3,727	0.7 %
United States Government and Agency Securities	-	84,024	-	-	84,024	15.2 %
Corporate Debt	-	145,081	-	-	145,081	26.3 %
Foreign Debt	-	23,332	-	-	23,332	4.2 %
State and Local Government	-	5,166	-	-	5,166	0.9 %
Other - Asset Backed	-	4,184	-	-	4,184	0.8 %
Subtotal - Fixed Income	-	265,514	-	-	265,514	48.1 %
Real Estate	-	-	25,791	-	25,791	4.7 %
Alternative Investments	-	-	22,974	-	22,974	4.2 %
Securities Lending	-	9,436	-	-	9,436	1.7 %
Securities Lending Collateral (a)	-	-	-	(10,672)	(10,672)	(1.9)%
Cash and Cash Equivalents	-	14,772	-	-	14,772	2.7 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	627	627	0.1 %
Total	$ 222,650	$ 290,232	$ 48,765	$ (10,045)	$ 551,602	100.0 %

(a) Amounts in "Other" column primarily represent an obligation to repay cash collateral received as part of the Securities Lending Program.
(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following table sets forth a reconciliation of changes in the fair value of assets classified as Level 3 in the fair value hierarchy for the pension assets:

	Corporate Debt	Real Estate	Alternative Investments	Total Level 3
		(in thousands)		
Balance as of January 1, 2012	$ 746	$ 19,112	$ 18,762	$ 38,620
Actual Return on Plan Assets				
Relating to Assets Still Held as of the Reporting Date	-	3,533	1,203	4,736
Relating to Assets Sold During the Period	(263)	-	583	320
Purchases and Sales	(483)	3,146	2,426	5,089
Transfers into Level 3	-	-	-	-
Transfers out of Level 3	-	-	-	-
Balance as of December 31, 2012	$ -	$ 25,791	$ 22,974	$ 48,765

The following table presents the classification of OPEB plan assets within the fair value hierarchy as of December 31, 2012:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 52,245	$ -	$ -	$ -	$ 52,245	26.9 %
International	62,466	-	-	-	62,466	32.2 %
Subtotal - Equities	114,711	-	-	-	114,711	59.1 %
Fixed Income:						
Common Collective Trust - Debt	-	8,982	-	-	8,982	4.6 %
United States Government and Agency Securities	-	10,176	-	-	10,176	5.2 %
Corporate Debt	-	19,167	-	-	19,167	9.9 %
Foreign Debt	-	3,240	-	-	3,240	1.7 %
State and Local Government	-	901	-	-	901	0.5 %
Other - Asset Backed	-	1,217	-	-	1,217	0.6 %
Subtotal - Fixed Income	-	43,683	-	-	43,683	22.5 %
Trust Owned Life Insurance:						
International Equities	-	6,380	-	-	6,380	3.3 %
United States Bonds	-	20,128	-	-	20,128	10.3 %
Cash and Cash Equivalents	7,684	1,412	-	-	9,096	4.7 %
Other - Pending Transactions and Accrued Income (a)	-	-	-	130	130	0.1 %
Total	$ 122,395	$ 71,603	$ -	$ 130	$ 194,128	100.0 %

(a) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following table presents the classification of pension plan assets within the fair value hierarchy as of December 31, 2011:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 170,210	$ -	$ -	$ -	$ 170,210	33.8 %
International	46,667	-	-	-	46,667	9.3 %
Real Estate Investment Trusts	12,168	-	-	-	12,168	2.4 %
Common Collective Trust - International	-	15,030	-	-	15,030	3.0 %
Subtotal - Equities	229,045	15,030	-	-	244,075	48.5 %
Fixed Income:						
Common Collective Trust - Debt	-	3,072	-	-	3,072	0.6 %
United States Government and Agency Securities	-	66,195	-	-	66,195	13.2 %
Corporate Debt	-	115,209	746	-	115,955	23.0 %
Foreign Debt	-	22,308	-	-	22,308	4.4 %
State and Local Government	-	5,623	-	-	5,623	1.1 %
Other - Asset Backed	-	3,042	-	-	3,042	0.6 %
Subtotal - Fixed Income	-	215,449	746	-	216,195	42.9 %
Real Estate	-	-	19,112	-	19,112	3.8 %
Alternative Investments	-	-	18,762	-	18,762	3.7 %
Securities Lending	-	25,130	-	-	25,130	5.0 %
Securities Lending Collateral (a)	-	-	-	(27,589)	(27,589)	(5.5)%
Cash and Cash Equivalents	-	10,855	-	-	10,855	2.2 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	(3,069)	(3,069)	(0.6)%
Total	$ 229,045	$ 266,464	$ 38,620	$ (30,658)	$ 503,471	100.0 %

(a) Amounts in "Other" column primarily represent an obligation to repay cash collateral received as part of the Securities Lending Program.

(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following table sets forth a reconciliation of changes in the fair value of assets classified as Level 3 in the fair value hierarchy for the pension assets:

	Corporate Debt	Real Estate	Alternative Investments	Total Level 3
		(in thousands)		
Balance as of January 1, 2011	$ -	$ 9,732	$ 15,205	$ 24,937
Actual Return on Plan Assets				
Relating to Assets Still Held as of the Reporting Date	-	2,611	1,018	3,629
Relating to Assets Sold During the Period	-	-	349	349
Purchases and Sales	-	6,769	2,190	8,959
Transfers into Level 3	746	-	-	746
Transfers out of Level 3	-	-	-	-
Balance as of December 31, 2011	$ 746	$ 19,112	$ 18,762	$ 38,620

The following table presents the classification of OPEB plan assets within the fair value hierarchy as of December 31, 2011:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 44,707	$ -	$ -	$ -	$ 44,707	24.7 %
International	48,897	-	-	-	48,897	27.0 %
Common Collective Trust - Global	-	12,748	-	-	12,748	7.0 %
Subtotal - Equities	93,604	12,748	-	-	106,352	58.7 %
Fixed Income:						
Common Collective Trust - Debt	-	8,898	-	-	8,898	4.9 %
United States Government and Agency Securities	-	10,386	-	-	10,386	5.7 %
Corporate Debt	-	19,558	-	-	19,558	10.8 %
Foreign Debt	-	4,146	-	-	4,146	2.3 %
State and Local Government	-	1,082	-	-	1,082	0.6 %
Other - Asset Backed	-	246	-	-	246	0.1 %
Subtotal - Fixed Income	-	44,316	-	-	44,316	24.4 %
Trust Owned Life Insurance:						
International Equities	-	5,943	-	-	5,943	3.3 %
United States Bonds	-	20,290	-	-	20,290	11.2 %
Cash and Cash Equivalents	2,161	3,010	-	-	5,171	2.9 %
Other - Pending Transactions and Accrued Income (a)	-	-	-	(835)	(835)	(0.5)%
Total	$ 95,765	$ 86,307	$ -	$ (835)	$ 181,237	100.0 %

(a) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

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.

Accumulated Benefit Obligation	December 31, 2012	December 31, 2011
	(in thousands)	
Qualified Pension Plan	$ 603,461	$ 569,428
Nonqualified Pension Plans	200	168
Total	$ 603,661	$ 569,596

For the underfunded pension plans that had an accumulated benefit obligation in excess of plan assets, the projected benefit obligation, accumulated benefit obligation and fair value of plan assets of these plans as of December 31, 2012 and 2011 were as follows:

	December 31, 2012	December 31, 2011
	(in thousands)	
Projected Benefit Obligation	$ 618,974	$ 581,249
Accumulated Benefit Obligation	$ 603,661	$ 569,596
Fair Value of Plan Assets	551,602	503,471
Underfunded Accumulated Benefit Obligation	$ (52,059)	$ (66,125)

Estimated Future Benefit Payments and Contributions

I&M expects contributions and payments for the pension plans of $14.9 million during 2013. 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. In November 2012, changes to the retiree medical coverage were announced. Effective for retirements after December 2012, contributions to retiree medical coverage will be capped reducing exposure to future medical cost inflation. Effective for employees hired after December 2013, retiree medical coverage will not be provided. In December 2011, the prescription drug plan was amended for certain participants. The impact of the changes is reflected in the Benefit Plan Obligation table as plan amendments. 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 pension benefits and OPEB are as follows:

	Estimated Payments	
	Pension Plans	Other Postretirement Benefit Plans
	(in thousands)	
2013	$ 36,364	$ 16,803
2014	36,956	17,713
2015	38,690	18,862
2016	39,465	20,200
2017	40,345	21,282
Years 2018 to 2022, in Total	213,423	125,784

Components of Net Periodic Benefit Cost

The following table provides the components of net periodic benefit cost for the years ended December 31, 2012 and 2011:

	Pension Plans		Other Postretirement Benefit Plans	
	Years Ended December 31,			
	2012	2011	2012	2011
	(in thousands)			
Service Cost	$ 9,908	$ 9,447	$ 6,621	$ 6,119
Interest Cost	26,227	27,706	12,590	13,404
Expected Return on Plan Assets	(37,533)	(36,820)	(12,847)	(13,886)
Amortization of Prior Service Cost (Credit)	406	743	(2,383)	(236)
Amortization of Net Actuarial Loss	17,558	14,134	6,918	3,442
Net Periodic Benefit Cost	16,566	15,210	10,899	8,843
Capitalized Portion	(3,114)	(3,164)	(2,049)	(1,839)
Net Periodic Benefit Cost Recognized as Expense	$ 13,452	$ 12,046	$ 8,850	$ 7,004

Estimated amounts expected to be amortized to net periodic benefit costs (credits) and the impact on the balance sheet during 2013 are shown in the following table:

Components	Pension Plans	Other Postretirement Benefit Plans
	(in thousands)	
Net Actuarial Loss	$ 20,939	$ 7,463
Prior Service Cost (Credit)	195	(9,421)
Total Estimated 2013 Amortization	$ 21,134	$ (1,958)
Expected to be Recorded as		
Regulatory Asset	$ 19,852	$ (1,767)
Deferred Income Taxes	449	(67)
Net of Tax AOCI	833	(124)
Total	$ 21,134	$ (1,958)

American Electric Power System Retirement Savings Plan

I&M participates in an AEP 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, 2012 and 2011 was $9.7 million and $9.5 million, respectively.

6. BUSINESS SEGMENTS

I&M has one reportable segment, an electricity generation, transmission and distribution business. I&M's other activities are insignificant.

7. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

I&M is exposed to certain market risks as a major power producer and marketer of wholesale electricity, coal and emission allowances. These risks include commodity price risk, interest rate risk, credit risk and, to a lesser extent, foreign currency exchange risk. These risks represent the risk of loss that may impact I&M due to changes in the underlying market prices or rates. AEPSC, on behalf of I&M, manages these risks using derivative instruments.

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, focusing on seizing market opportunities to create value driven by expected changes in the market prices of the commodities in which AEPSC transacts on behalf of I&M. To accomplish these objectives, AEPSC, on behalf of 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.

AEPSC, on behalf of I&M, enters into power, coal, natural gas, interest rate and, to a lesser degree, heating oil and gasoline, emission allowance and other commodity contracts to manage the risk associated with the energy business. AEPSC, on behalf of I&M, enters into 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. AEPSC, on behalf of I&M, also engages in risk management of interest rate risk associated with debt financing and foreign currency risk associated with future purchase obligations denominated in foreign currencies. For disclosure purposes, these risks are grouped as "Interest Rate and Foreign Currency." 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 AEP's Board of Directors.

The following table represents the gross notional volume of outstanding derivative contracts as of December 31, 2012 and 2011:

Notional Volume of Derivative Instruments

	Volume December 31,		
Primary Risk Exposure	**2012**	**2011**	**Unit of Measure**
	(in thousands)		
Commodity:			
Power	64,791	109,326	MWhs
Coal	2,711	1,920	Tons
Natural Gas	6,922	5,081	MMBtus
Heating Oil and Gasoline	532	525	Gallons
Interest Rate	$ 16,584	$ 19,890	USD
Interest Rate and Foreign Currency	$ 200,000	$ 200,000	USD

Fair Value Hedging Strategies

AEPSC, on behalf of I&M, enters into interest rate derivative transactions as part of an overall strategy to manage the mix of fixed-rate and floating-rate debt. Certain interest rate derivative transactions effectively modify an exposure to interest rate risk by converting a portion of fixed-rate debt to a floating rate. Provided specific criteria are met, these interest rate derivatives are designated as fair value hedges.

Cash Flow Hedging Strategies

AEPSC, on behalf of I&M, enters into and designates as cash flow hedges certain derivative transactions for the purchase and sale of power, coal, natural gas and heating oil and gasoline ("Commodity") in order to manage the variable price risk related to the forecasted purchase and sale of these commodities. 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 fuel or energy purchases. I&M does not hedge all commodity price risk.

I&M's vehicle fleet is exposed to gasoline and diesel fuel price volatility. AEPSC, on behalf of I&M, enters into financial heating oil and gasoline derivative contracts in order to mitigate price risk of future fuel purchases. For disclosure purposes, these contracts are included with other hedging activities as "Commodity." I&M does not hedge all fuel price risk.

AEPSC, on behalf of I&M, enters into a variety of interest rate derivative transactions in order to manage interest rate risk exposure. Some interest rate derivative transactions effectively modify exposure to interest rate risk by converting a portion of floating-rate debt to a fixed rate. AEPSC, on behalf of I&M, also enters into interest rate derivative contracts to manage interest rate exposure related to future borrowings of fixed-rate debt. The forecasted fixed-rate debt offerings have a high probability of occurrence as the proceeds will be used to fund existing debt maturities and projected capital expenditures. I&M does not hedge all interest rate exposure.

At times, I&M is exposed to foreign currency exchange rate risks primarily when some fixed assets are purchased from foreign suppliers. In accordance with AEP's risk management policy, AEPSC, on behalf of I&M, may enter into foreign currency derivative transactions to protect against the risk of increased cash outflows resulting from a foreign currency's appreciation against the dollar. I&M does not hedge all foreign currency 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 sheet 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, supply and demand market data and assumptions. In order to determine the relevant fair values of the derivative instruments, management also 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. For the December 31, 2012 and 2011 balance sheets, I&M netted cash collateral received from third parties against short-term and long-term risk management assets and cash collateral paid to third parties against short-term and long-term risk management liabilities as follows:

December 31,
(in thousands)

2012		2011	
Cash Collateral Received Netted Against Risk Management Assets	Cash Collateral Paid Netted Against Risk Management Liabilities	Cash Collateral Received Netted Against Risk Management Assets	Cash Collateral Paid Netted Against Risk Management Liabilities
$ 867	$ 7,576	$ 2,752	$ 18,547

The following tables represent the gross fair value of derivative activity on the balance sheets as of December 31, 2012 and 2011:

Fair Value of Derivative Instruments
December 31, 2012

	Risk Management Contracts	Hedging Contracts		Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (d)
Balance Sheet Location	Commodity (a)	Commodity (a)	Interest Rate and Foreign Currency (a)			
			(in thousands)			
Derivative Instrument Assets	$ 134,821	$ -	$ -	$ 134,821	$ (84,478)	$ 50,343
Long-Term Portion of Derivative Instrument Assets	41,553	-	-	41,553	(18,124)	23,429
Derivative Instrument Assets – Hedges	-	368	-	368	(168)	200
Long-Term Portion of Derivative Instrument Assets – Hedges	-	148	-	148	(8)	140
Derivative Instrument Liabilities	116,147	-	-	116,147	(91,187)	24,960
Long-Term Portion of Derivative Instrument Liabilities	33,714	-	-	33,714	(20,100)	13,614
Derivative Instrument Liabilities – Hedges	-	1,099	19,524	20,623	(168)	20,455
Long-Term Portion of Derivative Instrument Liabilities – Hedges	-	292	-	292	(8)	284

Fair Value of Derivative Instruments
December 31, 2011

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate and Foreign Currency (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (c)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (d)
			(in thousands)			
Derivative Instrument Assets	$ 222,675	$ -	$ -	$ 222,675	$ (161,438)	$ 61,237
Long-Term Portion of Derivative Instrument Assets	68,047	-	-	68,047	(38,702)	29,345
Derivative Instrument Assets – Hedges	-	725	-	725	(448)	277
Long-Term Portion of Derivative Instrument Assets – Hedges	-	58	-	58	(41)	17
Derivative Instrument Liabilities	201,907	-	-	201,907	(178,216)	23,691
Long-Term Portion of Derivative Instrument Liabilities	52,441	-	-	52,441	(44,390)	8,051
Derivative Instrument Liabilities – Hedges	-	1,971	10,637	12,608	(448)	12,160
Long-Term Portion of Derivative Instrument Liabilities – Hedges	-	224	10,637	10,861	(41)	10,820

(a) Derivative instruments within these categories are reported 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) Amounts primarily include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging." Amounts also include de-designated risk management contracts.
(d) There are no derivative contracts subject to a master netting arrangement or similar agreement which are not offset in the statement of financial position.

The table below presents the activity of derivative risk management contracts for the years ended December 31, 2012 and 2011:

Amount of Gain (Loss) Recognized on
Risk Management Contracts
Years Ended December 31, 2012 and 2011

Location of Gain (Loss)	2012	2011
	(in thousands)	
Operating Revenues	$ 11,437	$ 12,878
Regulatory Assets (a)	(9,204)	(1,470)
Regulatory Liabilities (a)	(889)	(5,178)
Total Gain on Risk Management Contracts	$ 1,344	$ 6,230

(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. However, unrealized and some realized gains and losses in regulated jurisdictions 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 Fair Value Hedging Strategies

For fair value hedges (i.e. hedging the exposure to changes in the fair value of an asset, liability or an identified portion thereof attributable to a particular risk), the gain or loss on the derivative instrument as well as the offsetting gain or loss on the hedged item associated with the hedged risk impacts Net Income during the period of change.

I&M records realized and unrealized gains or losses on interest rate swaps that qualify for fair value hedge accounting treatment and any offsetting changes in the fair value of the debt being hedged in Interest on Long-Term Debt on the statements of income. During 2012 and 2011, I&M did not employ any fair value hedging strategies.

Accounting for Cash Flow Hedging Strategies

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows attributable to a particular risk), I&M initially reports the effective portion of 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. I&M's hedge ineffectiveness is recorded as a regulatory asset (for losses) or a regulatory liability (for gains).

Realized gains and losses on derivative contracts for the purchase and sale of power, coal and natural gas designated as cash flow hedges are included in Operating Revenues or Operation Expenses on the statements of income or in regulatory assets or regulatory liabilities on the balance sheets, depending on the specific nature of the risk being hedged. During 2012 and 2011, I&M designated power, coal and natural gas derivatives as cash flow hedges.

I&M reclassifies gains and losses on heating oil and gasoline derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income on the balance sheets into Operation Expenses, Maintenance Expenses or Depreciation Expense, as it relates to capital projects, on the statements of income. During 2012 and 2011, I&M designated heating oil and gasoline derivatives as cash flow hedges.

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 2012 and 2011, I&M designated interest rate derivatives as cash flow hedges.

The accumulated gains or losses related to foreign currency hedges are reclassified from Accumulated Other Comprehensive Income on the balance sheets into Depreciation Expense on the statements of income over the depreciable lives of the fixed assets designated as the hedged items in qualifying foreign currency hedging relationships.

During 2012 and 2011, hedge ineffectiveness was immaterial or nonexistent for all of the hedge strategies disclosed above.

The following tables provide details on designated, effective cash flow hedges included in Accumulated Other Comprehensive Income on the balance sheets and the reasons for changes in cash flow hedges for the years ended December 31, 2012 and 2011. All amounts in the following tables are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
Year Ended December 31, 2012

	Commodity Contracts	Interest Rate and Foreign Currency Contracts	Total Contracts
		(in thousands)	
Balance in AOCI as of December 31, 2011	$ (819)	$ (14,465)	$ (15,284)
Changes in Fair Value Recognized in AOCI	(987)	(5,777)	(6,764)
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:			
Operating Revenues	(43)	-	(43)
Operation Expenses	1,137	-	1137
Maintenance Expenses	(2)	-	(2)
Interest on Long-Term Debt	-	595	595
Utility Plant	(10)	-	(10)
Regulatory Assets (a)	278	-	278
Balance in AOCI as of December 31, 2012	$ (446)	$ (19,647)	$ (20,093)

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
Year Ended December 31, 2011

	Commodity Contracts	Interest Rate and Foreign Currency Contracts	Total Contracts
		(in thousands)	
Balance in AOCI as of December 31, 2010	$ (178)	$ (8,507)	$ (8,685)
Changes in Fair Value Recognized in AOCI	(1,294)	(6,913)	(8,207)
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:			
Operating Revenues	544	-	544
Operation Expenses	8	-	8
Maintenance Expenses	(64)	-	(64)
Interest on Long-Term Debt	-	955	955
Utility Plant	(90)	-	(90)
Regulatory Assets (a)	255	-	255
Balance in AOCI as of December 31, 2011	$ (819)	$ (14,465)	$ (15,284)

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

Cash flow hedges included in Accumulated Other Comprehensive Income on the balance sheets as of December 31, 2012 and 2011 were:

Impact of Cash Flow Hedges on the Balance Sheet
December 31, 2012

	Commodity	Interest Rate and Foreign Currency	Total
		(in thousands)	
Hedging Assets (a)	$ 200	$ -	$ 200
Hedging Liabilities (a)	931	19,524	20,455
AOCI Loss Net of Tax	(446)	(19,647)	(20,093)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(355)	(1,600)	(1,955)

Impact of Cash Flow Hedges on the Balance Sheet
December 31, 2011

	Commodity	Interest Rate and Foreign Currency	Total
		(in thousands)	
Hedging Assets (a)	$ 277	$ -	$ 277
Hedging Liabilities (a)	1,523	10,637	12,160
AOCI Loss Net of Tax	(819)	(14,465)	(15,284)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(712)	(595)	(1,307)

(a) Hedging assets and hedging liabilities are included in Derivative Instrument Assets – Hedges and Derivative Instrument Liabilities – Hedges on the balance sheets.

The actual amounts reclassified from Accumulated Other Comprehensive Income to Net Income can differ from the estimate above due to market price changes. As of December 31, 2012, the maximum length of time that I&M is hedging (with contracts subject to the accounting guidance for "Derivatives and Hedging") exposure to variability in future cash flows to forecasted transactions is 17 months).

Credit Risk

AEPSC, on behalf of I&M, limits credit risk in the 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. AEPSC, on behalf of I&M, uses Moody's, Standard and Poor's and current market-based qualitative and quantitative data as well as financial statements to assess the financial health of counterparties on an ongoing basis.

AEPSC, on behalf of I&M, uses standardized master agreements which may include collateral requirements. These master agreements facilitate the netting of cash flows associated with a single counterparty. Cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. The collateral agreements require a counterparty to post cash or letters of credit in the event an 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, collateral agreements allow for termination and liquidation of all positions in the event of a failure or inability to post collateral.

Collateral Triggering Events

Under the tariffs of the RTOs and Independent System Operators (ISOs) and a limited number of derivative and non-derivative contracts primarily related to competitive retail auction loads, I&M is obligated to post an additional amount of collateral if certain credit ratings decline below investment grade. The amount of collateral required fluctuates based on market prices and total exposure. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering items in contracts. I&M has not experienced a downgrade below investment grade. The following tables represent: (a) I&M's fair values of such derivative contracts, (b) the amount of collateral I&M would have been required to post for all derivative and non-derivative contracts if its credit ratings had declined below investment grade and (c) how much was attributable to RTO and ISO activities as of December 31, 2012 and 2011:

	Liabilities for Derivative Contracts with Credit Downgrade Triggers	Amount of Collateral I&M Would Have Been Required to Post	Amount Attributable to RTO and ISO Activities
		(in thousands)	
December 31, 2012	$ 1,483	$ 2,540	$ 2,411
December 31, 2011	6,418	3,983	3,983

As of December 31, 2012 and 2011, I&M was not required to post any collateral.

In addition, a majority of I&M's non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event by Parent or the obligor under outstanding debt or a third party obligation in excess of $50 million. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. The following table represents: (a) the fair value of these derivative liabilities subject to cross-default provisions prior to consideration of contractual netting arrangements, (b) the amount this exposure has been reduced by cash collateral posted by I&M and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering I&M's contractual netting arrangements as of December 31, 2012 and 2011:

	Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	Amount of Cash Collateral Posted	Additional Settlement Liability if Cross Default Provision is Triggered
		(in thousands)	
December 31, 2012	$ 53,499	$ 1,252	$ 40,240
December 31, 2011	59,936	5,200	28,339

8. 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 as of December 31, 2012 and 2011 are summarized in the following table:

December 31,			
2012		2011	
Book Value	Fair Value	Book Value	Fair Value
(in thousands)			
1,833,290	2,144,652	$ 1,823,085	$ 2,098,470

Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal

I&M records securities held in trust funds for decommissioning nuclear facilities and for the disposal of SNF at fair value. See "Nuclear Trust Funds" section of Note 1.

The following is a summary of nuclear trust fund investments as of December 31, 2012 and 2011:

	December 31,					
	2012			2011		
	Estimated Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments	Estimated Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments
	(in thousands)					
Cash and Cash Equivalents	$ 16.783	$ -	$ -	$ 18.229	$ -	$ -
Fixed Income Securities:						
United States Government	647.918	58,268	(747)	543.506	60.946	(547)
Corporate Debt	35.399	4.903	(1.352)	53,979	4.932	(1.536)
State and Local Government	270.090	1.006	(863)	329.986	(430)	(2.236)
Subtotal Fixed Income Securities	953,407	64.177	(2,962)	927.471	65.448	(4.319)
Equity Securities - Domestic	735.582	284.599	(76.557)	646.032	214.748	(79.536)
Spent Nuclear Fuel and Decommissioning Trusts	$ 1.705.772	$ 348.776	$ (79.519)	$ 1.591.732	$ 280.196	$ (83.855)

The following table provides the securities activity within the decommissioning and SNF trusts for the years ended December 31, 2012 and 2011:

	Years Ended December 31, 2012	2011
	(in thousands)	
Proceeds from Investment Sales	$ 987,550	$ 1,110,909
Purchases of Investments	1,045,422	1,166,690
Gross Realized Gains on Investment Sales	24,605	33,382
Gross Realized Losses on Investment Sales	8,881	22,159

The adjusted cost of debt securities was $889 million and $862 million as of December 31, 2012 and 2011, respectively. The adjusted cost of equity securities was $451 million and $431 million as of December 31, 2012 and 2011, respectively.

The fair value of debt securities held in the nuclear trust funds, summarized by contractual maturities, as of December 31, 2012 was as follows:

	Fair Value of Debt Securities
	(in thousands)
Within 1 year	$ 80,993
1 year – 5 years	373,532
5 years – 10 years	265,885
After 10 years	232,997
Total	$ 953,407

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, the financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2012 and 2011. 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.

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2012

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Derivative Instrument Assets					
Risk Management Commodity Contracts (a) (b)	$ 2,858	$ 120,242	$ 11,717	$ (84,474)	$ 50,343
Derivative Instrument Assets – Hedges					
Cash Flow Hedges – Commodity (a)	-	330	-	(130)	200
Other Special Funds					
Cash and Cash Equivalents (d)	6,508	-	-	10,275	16,783
Fixed Income Securities:					
United States Government	-	647,918	-	-	647,918
Corporate Debt	-	35,399	-	-	35,399
State and Local Government	-	270,090	-	-	270,090
Subtotal Fixed Income Securities	-	953,407	-	-	953,407
Equity Securities – Domestic (e)	735,582	-	-	-	735,582
Total Other Special Funds	742,090	953,407	-	10,275	1,705,772
Total Assets	$ 744,948	$ 1,073,979	$ 11,717	$ (74,329)	$ 1,756,315
Liabilities:					
Derivative Instrument Liabilities					
Risk Management Commodity Contracts (a) (b)	$ 1,346	$ 110,621	$ 4,176	$ (91,183)	$ 24,960
Derivative Instrument Liabilities - Hedges					
Cash Flow Hedges:					
Commodity (a)	-	1,061	-	(130)	931
Interest Rate/Foreign Currency	-	19,524	-	-	19,524
Total Derivative Instrument Liabilities – Hedges	-	20,585	-	(130)	20,455
Total Liabilities	$ 1,346	$ 131,206	$ 4,176	$ (91,313)	$ 45,415

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2011

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Derivative Instrument Assets					
Risk Management Commodity Contracts (a) (b)	$ 3,001	$ 203,175	$ 16,305	$ (162,227)	$ 60,254
Dedesignated Risk Management Contracts (c)	-	-	-	983	983
Total Derivative Instrument Assets	3,001	203,175	16,305	(161,244)	61,237
Derivative Instrument Assets – Hedges					
Cash Flow Hedges – Commodity (a)	-	702	-	(425)	277
Other Special Funds					
Cash and Cash Equivalents (d)	-	5,431	-	12,798	18,229
Fixed Income Securities:					
United States Government	-	543,506	-	-	543,506
Corporate Debt	-	53,979	-	-	53,979
State and Local Government	-	329,986	-	-	329,986
Subtotal Fixed Income Securities	-	927,471	-	-	927,471
Equity Securities – Domestic (e)	646,032	-	-	-	646,032
Total Other Special Funds	646,032	932,902	-	12,798	1,591,732
Total Assets	$ 649,033	$ 1,136,779	$ 16,305	$ (148,871)	$ 1,653,246
Liabilities:					
Derivative Instrument Liabilities					
Risk Management Commodity Contracts (a) (b)	$ 1,626	$ 185,092	$ 14,995	$ (178,022)	$ 23,691
Derivative Instrument Liabilities - Hedges					
Cash Flow Hedges:					
Commodity (a)	-	1,901	47	(425)	1,523
Interest Rate/Foreign Currency	-	10,637	-	-	10,637
Total Derivative Instrument Liabilities – Hedges	-	12,538	47	(425)	12,160
Total Liabilities	$ 1,626	$ 197,630	$ 15,042	$ (178,447)	$ 35,831

(a) 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."
(b) Substantially comprised of power contracts.
(c) Represents contracts that were originally MTM but were subsequently elected as normal under the accounting guidance for "Derivatives and Hedging." At the time of the normal election, the MTM value was frozen and no longer fair valued. This MTM value will be amortized into revenues over the remaining life of the contracts.
(d) Amounts in "Other" column primarily represent accrued interest receivables from financial institutions. Level 2 amounts primarily represent investments in money market funds.
(e) Amounts represent publicly traded equity securities and equity-based mutual funds.

There have been no transfers between Level 1 and Level 2 during the years ended December 31, 2012 and 2011.

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, 2012	Net Risk Management Assets (Liabilities)
	(in thousands)
Balance as of December 31, 2011	$ 1,263
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(3,554)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	13
Purchases, Issuances and Settlements (c)	7,734
Transfers into Level 3 (d) (e)	860
Transfers out of Level 3 (e) (f)	(1,144)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	2,369
Balance as of December 31, 2012	$ 7,541

Year Ended December 31, 2011	Net Risk Management Assets (Liabilities)
	(in thousands)
Balance as of December 31, 2010	$ 3,108
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(1,261)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	(47)
Purchases, Issuances and Settlements (c)	847
Transfers into Level 3 (d) (e)	1,531
Transfers out of Level 3 (e) (f)	(1,906)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	(1,009)
Balance as of December 31, 2011	$ 1,263

(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) Represents the settlement of risk management commodity contracts for the reporting period.
(d) Represents existing assets or liabilities that were previously categorized as Level 2.
(e) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.
(f) Represents existing assets or liabilities that were previously categorized as Level 3.
(g) Relates to the net gains (losses) of those contracts that are not reflected on the statements of income. These net gains (losses) are recorded as regulatory assets/liabilities.

The following table quantifies the significant unobservable inputs used in developing the fair value of Level 3 positions as of December 31, 2012:

	Fair Value		Valuation	Significant	Forward Price Range	
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High
	(in thousands)					
Energy Contracts	$ 10,516	$ 2,693	Discounted Cash Flow	Forward Market Price	$ 9.40	$ 68.80
FTRs	1,201	1,483	Discounted Cash Flow	Forward Market Price	(3.21)	14.79
Total	$ 11,717	$ 4,176				

(a) Represents market prices in dollars per MWh.

9. INCOME TAXES

The details of income taxes as reported are as follows:

	Years Ended December 31, 2012	2011
	(in thousands)	
Charged (Credited) to Operating Expenses, Net:		
Current	$ (5,100)	$ (78,981)
Deferred	51,796	135,782
Deferred Investment Tax Credits	(4,502)	(2,783)
Total	42,194	54,018
Charged (Credited) to Nonoperating Income, Net:		
Current	(4,157)	(1,434)
Deferred	1,340	(956)
Total	(2,817)	(2,390)
Total Income Taxes	$ 39,377	$ 51,628

Shown below 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 rate and the amount of income taxes reported:

	Years Ended December 31, 2012	2011
	(in thousands)	
Net Income	$ 118,457	$ 149,674
Income Tax Expense	39,377	51,628
Pretax Income	$ 157,834	$ 201,302
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 55,242	$ 70,456
Increase (Decrease) in Income Taxes Resulting from the Following Items:		
Depreciation	8,659	7,895
Nuclear Fuel Disposal Costs	225	(1,400)
AFUDC	(7,218)	(9,223)
Removal Costs	(5,490)	(5,566)
Investment Tax Credits, Net	(4,502)	(2,783)
State and Local Income Taxes, Net	(1,559)	(1,377)
Other	(5,980)	(6,374)
Income Tax Expense	$ 39,377	$ 51,628
Effective Income Tax Rate	24.9%	25.6%

The following table shows elements of the net deferred tax liability and significant temporary differences:

	December 31, 2012	2011
	(in thousands)	
Deferred Tax Assets	$ 832,086	$ 774,052
Deferred Tax Liabilities	(1,868,399)	(1,712,670)
Net Deferred Tax Liabilities	$ (1,036,313)	$ (938,618)
Property Related Temporary Differences	$ (373,831)	$ (317,265)
Amounts Due from Customers for Future Federal Income Taxes	(37,633)	(28,551)
Deferred State Income Taxes	(115,479)	(107,751)
Deferred Income Taxes on Other Comprehensive Loss	14,734	14,319
Accrued Nuclear Decommissioning	(475,223)	(435,916)
Postretirement Benefits	26,330	50,121
Net Operating Loss Carryforward	31,233	12,986
Accrued Pensions	24,880	27,953
Regulatory Assets	(88,696)	(116,474)
All Other, Net	(42,628)	(38,040)
Net Deferred Tax Liabilities	$ (1,036,313)	$ (938,618)

AEP System Tax Allocation Agreement

I&M joins in the filing of a consolidated federal income tax return with its affiliates in the AEP System. The allocation of the AEP System's current consolidated federal income tax to the AEP System companies allocates the benefit of current tax losses to the AEP System companies giving rise to such losses in determining their current tax expense. The tax benefit of the Parent is allocated to its subsidiaries with taxable income. With the exception of the loss of the Parent, the method of allocation reflects a separate return result for each company in the consolidated group.

Federal and State Income Tax Audit Status

I&M and other AEP subsidiaries are no longer subject to U.S. federal examination for years before 2009. I&M and other AEP subsidiaries completed the examination of the years 2007 and 2008 in April 2011 and settled all outstanding issues on appeal for the years 2001 through 2006 in October 2011. The settlements did not materially impact net income, cash flows or financial condition. The Internal Revenue Service examination of years 2009 and 2010 started in October 2011. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for federal income taxes have been made for potential liabilities resulting from such matters. In addition, I&M accrues interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to materially impact net income.

I&M and other AEP subsidiaries file income tax returns in various state and local jurisdictions. These taxing authorities routinely examine the tax returns. I&M and other AEP subsidiaries are currently under examination in several state and local jurisdictions. Management believes that previously filed tax returns have positions that may be challenged by these tax authorities. However, management believes that adequate provisions for income taxes have been made for potential liabilities resulting from such challenges and that the ultimate resolution of these audits will not materially impact net income. With few exceptions, I&M and other AEP subsidiaries are no longer subject to state or local income tax examinations by tax authorities for years before 2008.

Net Income Tax Operating Loss Carryforward

In 2011, I&M sustained a $125 million federal net income tax operating loss driven primarily by bonus depreciation, pension plan contributions and other book versus tax temporary differences. As a result, I&M accrued deferred federal income tax benefits in 2011 and 2012 and expects to realize the federal benefit in future periods as there was insufficient capacity in prior periods to carry the net operating loss back. Management anticipates future taxable income will be sufficient to realize the net income tax operating loss tax benefits before the federal carryforward expires after 2032.

Tax Credit Carryforward

The AEP System sustained consolidated federal income tax net operating losses in 2011 and 2009 along with lower AEP consolidated federal taxable income in 2010, resulting in unused federal income tax credits. As of December 31, 2012, I&M had federal tax credit carryforwards of $2.5 million which will expire in the years 2028 through 2031. I&M anticipates future federal taxable income which will be sufficient to realize the tax benefits of the federal tax credits before they expire unused.

Uncertain Tax Positions

I&M and other AEP subsidiaries recognize interest accruals related to uncertain tax positions in interest income or expense as applicable and penalties in Penalties in accordance with the accounting guidance for "Income Taxes."

The following table shows amounts reported for interest expense, interest income and reversal of prior period interest expense:

	Years Ended December 31, 2012	2011
	(in thousands)	
Interest Expense	$ 1,355	$ -
Interest Income	-	2,234
Reversal of Prior Period Interest Expense	-	1,075

The following table shows balances for amounts accrued for the receipt of interest and payment of interest and penalties:

	December 31, 2012	2011
	(in thousands)	
Accrual for Receipt of Interest	$ -	$ 630
Accrual for Payment of Interest and Penalties	1,337	145

The reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

	2012	2011
	(in thousands)	
Balance as of January 1,	$ 14,071	$ 23,134
Increase - Tax Positions Taken During a Prior Period	2,266	9,256
Decrease - Tax Positions Taken During a Prior Period	(1,252)	(8,622)
Increase - Tax Positions Taken During the Current Year	-	-
Decrease - Tax Positions Taken During the Current Year	-	-
Decrease - Settlements with Taxing Authorities	-	(6,687)
Decrease - Lapse of the Applicable Statute of Limitations	-	(3,010)
Balance as of December 31,	$ 15,085	$ 14,071

The total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate is $1.2 million and $654 thousand for 2012 and 2011, respectively. Management believes that there will be no significant net increase or decrease in unrecognized benefits within 12 months of the reporting date.

Federal Tax Legislation

In December 2011, the U.S. Treasury Department issued guidance regarding the deduction and capitalization of expenditures related to tangible property. The guidance was in the form of proposed and temporary regulations and generally is effective for tax years beginning in 2012. In November 2012, the effective date was moved to tax years beginning in 2014. Further, the notice stated that the U. S. Treasury Department anticipates that the final regulations will contain changes from the temporary regulations. Management will evaluate the impact of these regulations once they are issued.

The American Taxpayer Relief Act of 2012 (the 2012 Act) was enacted in January 2013. Included in the 2012 Act was a one-year extension of the 50% bonus depreciation. The 2012 Act also retroactively extended the life of research and development, employment and several energy tax credits, which expired at the end of 2011. The enacted provisions will not materially impact net income or financial condition but are expected to have a favorable impact on cash flows in 2013.

State Tax Legislation

Legislation was passed by the state of Indiana in May 2011 enacting a phased reduction in corporate income tax rates from 8.5% to 6.5%. The 8.5% Indiana corporate income tax rate will be reduced 0.5% each year beginning after June 30, 2012 with the final reduction occurring in years beginning after June 30, 2015.

In May 2011, Michigan repealed its Business Tax regime and replaced it with a traditional corporate net income tax with a rate of 6%, effective January 1, 2012.

During the third quarter of 2012, the state of West Virginia achieved certain minimum levels of shortfall reserve funds. As a result, the West Virginia corporate income tax rate will be reduced from 7.75% to 7.0% in 2013. The enacted provisions will not materially impact net income, cash flows or financial condition.

10. LEASES

Leases of property, plant and equipment are for periods up to 35 years and require payments of related property taxes, maintenance and operating costs. The majority of the leases have purchase or renewal options and will be renewed or replaced by other leases.

Lease rentals for both operating and capital leases are generally charged to Operation Expenses and Maintenance Expenses in accordance with rate-making treatment for regulated operations. The components of rental costs are as follows:

	Years Ended December 31, 2012	Years Ended December 31, 2011
	(in thousands)	
Net Lease Expense on Operating Leases	$ 95,509	$ 94,317
Amortization of Capital Leases	130,239	103,361
Interest on Capital Leases	8,477	8,751
Total Lease Rental Costs	$ 234,225	$ 206,429

The following table shows the property, plant and equipment under capital leases and related obligations recorded on the balance sheets.

	December 31, 2012	2011
	(in thousands)	
Property, Plant and Equipment Under Capital Leases		
Production	$ 19,102	$ 16,100
Other Property, Plant and Equipment	198,762	216,087
Total Property, Plant and Equipment	217,864	232,187
Accumulated Amortization	13,154	12,779
Net Property, Plant and Equipment Under Capital Leases	$ 204,710	$ 219,408
Obligations Under Capital Leases:		
Noncurrent	$ 115,315	$ 140,888
Current	89,395	78,520
Total Obligations Under Capital Leases	$ 204,710	$ 219,408

Future minimum lease payments consisted of the following as of December 31, 2012:

	Capital Leases	Noncancelable Operating Leases
	(in thousands)	
2013	$ 131,162	$ 98,719
2014	85,264	98,673
2015	28,338	97,266
2016	6,331	89,872
2017	3,344	84,142
Later Years	11,781	423,279
Total Future Minimum Lease Payments	266,220	$ 891,951
Less Estimated Interest Element	61,510	
Estimated Present Value of Future Minimum Lease Payments	$ 204,710	

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 either the unamortized balance or 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. As of December 31, 2012, the maximum potential loss for these lease agreements assuming the fair value of the equipment is zero at the end of the lease term is $2.4 million. Historically, at the end of the lease term the fair value has been in excess of the unamortized balance.

Rockport Lease

AEGCo and I&M entered into a sale-and-leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee), an unrelated, unconsolidated trustee for Rockport Plant Unit 2 (the Plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and securities in a private placement to certain institutional investors.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the Plant and leases it equally to AEGCo and I&M. The lease is accounted for as an operating lease with the payment obligations included in the future minimum lease payments schedule above. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the Plant. AEP, AEGCo and I&M have no ownership interest in the Owner Trustee and do not guarantee its debt. I&M's future minimum lease payments for this sale-and-leaseback transaction as of December 31, 2012 are as follows:

Future Minimum Lease Payments	**(in millions)**
2013	$ 74
2014	74
2015	74
2016	74
2017	74
Later Years	369
Total Future Minimum Lease Payments	$ 739

Railcar Lease

In June 2003, AEP Transportation LLC (AEP Transportation), a subsidiary of AEP, entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The lease is accounted for as an operating lease. In January 2008, AEP Transportation assigned the remaining 848 railcars under the original lease agreement to I&M (390 railcars) and SWEPCo (458 railcars). The assignment is accounted for as an operating lease. The initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. I&M intends to renew the lease for the full lease term of twenty years via the renewal options. The future minimum lease obligation is $14 million for the remaining railcars as of December 31, 2012. These obligations are included in the future minimum lease payments schedule earlier in this note.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under a return-and-sale option will equal at least a lessee obligation amount specified in the lease, which declines from approximately 84% under the current five-year lease term to 77% at the end of the 20-year term of the projected fair value of the equipment. I&M assumed the guarantee under the return-and-sale option. I&M's maximum potential loss related to the guarantee is approximately $12 million assuming the fair value of the equipment is zero at the end of the current five-year lease term. However, management believes that the fair value would produce a sufficient sales price to avoid any loss.

I&M Nuclear Fuel Leases

In December 2007, I&M entered into a sale-and-leaseback transaction with Citicorp Leasing, Inc. (CLI), an unrelated, unconsolidated, wholly-owned subsidiary of Citibank, N.A. to lease nuclear fuel for the Cook Plant. In December 2007, I&M sold a portion of its unamortized nuclear fuel inventory to CLI at cost for $85 million. The lease had a variable rate based on one month LIBOR and was accounted for as a capital lease with lease terms up to 60 months. This lease terminated in 2012.

In September 2009, I&M entered into a sale-and-leaseback transaction for $102.3 million with DCC Fuel LLC (DCC) to lease nuclear fuel for the Cook Plant. DCC 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 rate of 5.44% and is a capital lease with a term of 48 months. I&M makes payments on the lease semi-annually in April and October. Payments began in April 2010.

In April 2010, I&M entered into a sale-and-leaseback transaction for $84.6 million with DCC Fuel II LLC (DCC II) to lease nuclear fuel for the Cook Plant. DCC II 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 rate of 4% and is a capital lease with a term of 54 months. I&M makes payments on the lease semi-annually in April and October. Payments began in October 2010.

In December 2010, I&M entered into a sale-and-leaseback transaction for $67.9 million with DCC Fuel III LLC (DCC III) to lease nuclear fuel for the Cook Plant. DCC III 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 capital lease with a term of 54 months. I&M makes payments on the lease monthly. Payments began in January 2011.

In November 2011, I&M entered into a sale-and-leaseback transaction for $110 million with DCC Fuel IV LLC (DCC IV) to lease nuclear fuel for the Cook Plant. DCC IV 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 for $65 million and a fixed rate of 2.12% for $45 million. The lease is a capital lease with a term of 54 months. I&M makes payments on the lease quarterly in February, May, August and November. Payments began in February 2012.

In April 2012, I&M entered into a sale-and-leaseback transaction for $110 million with DCC Fuel V LLC (DCC V). DCC V 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 capital lease with a term of 54 months. I&M makes payments on the lease quarterly in January, April, July and October. Payments began in July 2012.

The nuclear fuel leases are recorded net in Utility Plant. The capital lease obligations and future minimum lease payments for the nuclear fuel leases are included in the tables above.

11. FINANCING ACTIVITIES

Preferred Stock

In December 2011, I&M redeemed all of its outstanding preferred stock, resulting in a loss. The par value of preferred stock redeemed and the loss recorded was $8.1 million and $314 thousand, respectively. I&M redeemed 11,055 shares, 55,257 shares, and 14,412 shares of its 4.12% series, 4.125% series, and 4.56% series, respectively, during 2011.

Long-term Debt

There are certain limitations on establishing liens against I&M's assets under indentures. None of the long-term debt obligations of I&M have been guaranteed or secured by AEP or any of its affiliates.

The following details long-term debt outstanding as of December 31, 2012 and 2011:

Type of Debt	Maturity	Weighted Average Interest Rate as of December 31, 2012	Interest Rate Ranges as of December 31, 2012	Interest Rate Ranges as of December 31, 2011	Outstanding as of December 31, 2012	Outstanding as of December 31, 2011
					(in thousands)	
Senior Unsecured Notes	2012-2037	6.24%	5.05%-7.00%	5.05%-7.00%	$ 1,175,000	$ 1,275,000
Pollution Control Bonds (a)	2012-2025 (b)	4.03%	0.11%-6.25%	0.06%-6.25%	267,000	267,000
Spent Nuclear Fuel Liability (c)					265,249	265,065
Other Long-term Debt (d)	2015-2025	2.39%	1.72%-6.00%	6.00%	130,430	20,927
Unamortized Discount, Net					(4,389)	(4,907)
Total Long-term Debt					$ 1,833,290	$ 1,823,085

(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, standby bond purchase agreements and insurance policies support certain series.

(b) Certain pollution control bonds are subject to redemption earlier than the maturity date. Consequently, these bonds have been classified for maturity and repayment purposes based on the mandatory redemption date.

(c) Spent nuclear fuel obligation consists of a liability along with accrued interest for disposal of spent nuclear fuel (see "SNF Disposal" section of Note 4).

(d) In 2012, I&M issued a $110 million three-year credit facility to be used for general corporate purposes.

Long-term debt outstanding as of December 31, 2012 is payable as follows:

	(in thousands)
2013	$ 84,063
2014	276,055
2015	229,933
2016	1,360
2017	1,479
After 2017	1,244,789
Principal Amount	1,837,679
Unamortized Discount, Net	(4,389)
Total Long-term Debt Outstanding	$ 1,833,290

In March 2013, I&M issued $250 million of 3.2% Senior Unsecured Notes due in 2023.

In April 2013, I&M reacquired $40 million of 5.25% Pollution Control Bonds due in 2025. The variable rate bonds are held by a trustee, on behalf of I&M.

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.

Federal Power Act

The Federal Power Act prohibits I&M from participating "in the making or paying of any dividends of such public utility from any funds properly included in capital account." The term "capital account" is not defined in the Federal Power Act or its regulations. Management understands "capital account" to mean the book value of the common stock.

Additionally, the Federal Power Act creates a reserve on earnings attributable to hydroelectric generating plants. Because of its ownership of such plants, this reserve applies to I&M.

None of these restrictions limit the ability of I&M to pay dividends out of retained earnings.

Leverage Restrictions

Pursuant to the credit agreement leverage restrictions, I&M must maintain a percentage of debt to total capitalization at a level that does not exceed 67.5%. As of December 31, 2012, none of I&M's retained earnings have restrictions related to the payment of dividends to Parent.

Utility Money Pool – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of the subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries. The AEP System Utility Money Pool operates in accordance with the terms and conditions approved in a regulatory order. The amount of outstanding loans to the Utility Money Pool as of December 31, 2012 and 2011 is included in Notes Receivable from Associated Companies on the balance sheets. I&M's money pool activity and its corresponding authorized borrowing limits for the years ended December 31, 2012 and 2011 are described in the following table:

Years Ended December 31,	Maximum Borrowings from Utility Money Pool	Maximum Loans to Utility Money Pool	Average Borrowings from Utility Money Pool	Average Loans to Utility Money Pool	Loans to Utility Money Pool as of December 31,	Authorized Short-term Borrowing Limit
			(in thousands)			
2012	$ -	$ 348,852	$ -	$ 189,345	$ 103,619	$ 500,000
2011	57,352	214,030	23,793	67,202	90,442	500,000

Maximum, minimum and average interest rates for funds borrowed from and loaned to the Utility Money Pool for the years ended December 31, 2012 and 2011 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 Rate for Funds Borrowed from the Utility Money Pool	Average Interest Rate for Funds Loaned to the Utility Money Pool
2012	0.00%	-%	-%	0.39%	-%	0.46%
2011	0.53%	0.11%	0.56%	0.06%	0.39%	0.39%

Interest expense related to the Utility Money Pool is included in Interest on Debt to Associated Companies. I&M incurred interest expense for amounts borrowed from the Utility Money Pool of $24 thousand for the year ended December 31, 2011.

Interest income related to the Utility Money Pool is included in Interest and Dividend Income. I&M earned interest income for amounts advanced to the Utility Money Pool of $901 thousand and $211 thousand for the years ended December 31, 2012 and 2011, respectively.

Credit Facilities

For a discussion of credit facilities, see "Letters of Credit" section of Note 4.

Sale of Receivables – AEP Credit

Under a sale of receivables arrangement, I&M sells, without recourse, certain of its customer accounts receivable and accrued unbilled revenue balances to AEP Credit and is charged a fee based on AEP Credit's financing and administrative costs and I&M's uncollectible accounts experience. I&M manages and services its customer accounts receivable sold.

In 2012, AEP Credit renewed its receivables securitization agreement. The agreement provides a commitment of $700 million from bank conduits to finance receivables from AEP Credit. A commitment of $385 million expires in June 2013 and the remaining commitment of $315 million expires in June 2015.

The amount of accounts receivable and accrued unbilled revenues under the sale of receivables agreement as of December 31, 2012 and 2011 was $123.4 million and $121.6 million, respectively.

The fees paid to AEP Credit for customer accounts receivable sold were $6.1 million and $6.2 million for the years ended December 31, 2012 and 2011, respectively.

I&M's proceeds on the sale of receivables to AEP Credit were $1.3 billion and $1.3 billion for the years ended December 31, 2012 and 2011, respectively.

12. RELATED PARTY TRANSACTIONS

For other related party transactions, also see "AEP System Tax Allocation Agreement" section of Note 9 in addition to "Utility Money Pool – AEP System" and "Sale of Receivables – AEP Credit" sections of Note 11.

Interconnection Agreement

APCo, I&M, KPCo, OPCo and AEPSC are parties to the Interconnection Agreement, which defines the sharing of costs and benefits associated with their generating plants. This sharing is based upon each AEP utility subsidiary's MLR and is calculated monthly on the basis of each AEP utility subsidiary's maximum peak demand in relation to the sum of the maximum peak demands of all four AEP utility subsidiaries during the preceding 12 months. In addition, APCo, I&M, KPCo and OPCo are parties to the AEP System Interim Allowance Agreement, which provides, among other things, for the transfer of SO_2 allowances associated with the transactions under the Interconnection Agreement.

In October 2012, the AEP East Companies submitted several filings. The AEP East Companies asked the FERC to terminate the existing Interconnection Agreement and to approve a new Power Coordination Agreement among APCo, I&M and KPCo. A decision from the FERC is expected in mid-2013. See "Termination of Interconnection Agreement" section of Note 2.

Power, gas and risk management activities are conducted by AEPSC and profits and losses are allocated under the SIA to members of the Interconnection Agreement, PSO and SWEPCo. Risk management activities involve the purchase and sale of electricity and gas under physical forward contracts at fixed and variable prices. In addition, the risk management of electricity, and to a lesser extent gas contracts, includes exchange traded futures and options and OTC options and swaps. The majority of these transactions represent physical forward contracts in the AEP System's traditional marketing area and are typically settled by entering into offsetting contracts. In addition, AEPSC enters into transactions for the purchase and sale of electricity and gas options, futures and swaps and for the forward purchase and sale of electricity outside of the AEP System's traditional marketing area.

CSW Operating Agreement

PSO, SWEPCo and AEPSC are parties to a Restated and Amended Operating Agreement originally dated as of January 1, 1997 (CSW Operating Agreement), which was approved by the FERC. The CSW Operating Agreement requires PSO and SWEPCo to maintain adequate annual planning reserve margins and requires that capacity in excess of the required margins be made available for sale to other operating companies as capacity commitments. Parties are compensated for energy delivered to recipients based upon the deliverer's incremental cost plus a portion of the recipient's savings realized by the purchaser that avoids the use of more costly alternatives.

System Integration Agreement (SIA)

The SIA provides for the integration and coordination of AEP East Companies' and AEP West Companies' zones. This includes joint dispatch of generation within the AEP System and the distribution, between the two zones, of costs and benefits associated with the transfers of power between the two zones (including sales to third parties and risk management and trading activities). The SIA is designed to function as an umbrella agreement in addition to the Interconnection Agreement and the CSW Operating Agreement, each of which controls the distribution of costs and benefits within a zone.

Power generated, allocated or provided under the Interconnection Agreement or CSW Operating Agreement is primarily sold to customers at rates approved by the public utility commission in the jurisdiction of sale.

Under both the Interconnection Agreement and CSW Operating Agreement, power generated that is not needed to serve the native load of the AEP System is sold in the wholesale market by AEPSC on behalf of the generating company.

Affiliated Revenues and Purchases

The following table shows the revenues derived from sales under the Interconnection Agreement, direct sales to affiliates, net transmission agreement sales, natural gas contracts with AEPES and other revenues for the years ended December 31, 2012 and 2011:

Related Party Revenues	Years Ended December 31, 2012	2011
	(in thousands)	
Sales under Interconnection Agreement	$ 265,923	$ 308,336
Direct Sales to West Affiliates	218	908
Transmission Agreement and Transmission Coordination Agreement Sales	758	9,379
Natural Gas Contracts with AEPES	-	92
Other Revenues	1,509	1,469

The following table shows the purchased power expenses incurred for purchases under Interconnection Agreement and from affiliates for the years ended December 31, 2012 and 2011:

Related Party Purchases	Years Ended December 31, 2012	2011
	(in thousands)	
Purchases under Interconnection Agreement	$ 147,502	$ 124,598
Direct Purchases from West Affiliates	36	147
Purchases from AEGCo	238,866	228,739

System Transmission Integration Agreement

AEP's System Transmission Integration Agreement provides for the integration and coordination of the planning, operation and maintenance of the transmission facilities of AEP East Companies' and AEP West Companies' zones. Similar to the SIA, the System Transmission Integration Agreement functions as an umbrella agreement in addition to the Transmission Agreement (TA) and the Transmission Coordination Agreement (TCA). The System Transmission Integration Agreement contains two service schedules that govern:

- The allocation of transmission costs and revenues.
- The allocation of third-party transmission costs and revenues and AEP System dispatch costs.

The System Transmission Integration Agreement anticipates that additional service schedules may be added as circumstances warrant.

APCo, I&M, KPCo and OPCo are parties to a TA, effective November 2010, defining how they share the costs associated with their relative ownership of the extra-high-voltage transmission system (facilities rated 345 kV and above) and certain facilities operated at lower voltages (138 kV and above). I&M's net charges recorded related to the TA for the years ended December 31, 2012 and 2011 were $5.7 million and $1.5 million, respectively. The charges are recorded in Operation Expenses.

PSO, SWEPCo and AEPSC are parties to the TCA, dated January 1, 1997, revised 1999 and 2011, as restated and amended, by and among PSO, SWEPCo and AEPSC, in connection with the operation of the transmission assets of the two AEP utility subsidiaries. The TCA has been approved by the FERC and establishes a coordinating committee, which is charged with overseeing the coordinated planning of the transmission facilities of the parties to the agreement. This includes the performance of transmission planning studies, the interaction of such companies with independent system operators (ISO) and other regional bodies interested in transmission planning and compliance with the terms of the OATT filed with the FERC and the rules of the FERC relating to such a tariff.

Unit Power Agreements (UPA)

UPA between AEGCo and I&M

A UPA between AEGCo and I&M (the I&M Power Agreement) provides for the sale by AEGCo to I&M of all the power (and the energy associated therewith) available to AEGCo at the Rockport Plant unless it is sold to another utility. Subsequently, I&M assigns 30% of the power to KPCo. See the "UPA between AEGCo and KPCo" section below. 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 its operating and other expenses, including a rate of return on the common equity of AEGCo as approved by the FERC. The I&M Power Agreement will continue in effect until the expiration of the lease term of Unit 2 of the Rockport Plant unless extended in specified circumstances.

UPA between AEGCo and KPCo

Pursuant to an assignment between I&M and KPCo and a UPA between KPCo and AEGCo, AEGCo sells KPCo 30% of the power (and the energy associated therewith) available to AEGCo from both units of the Rockport Plant. KPCo pays to AEGCo in consideration for the right to receive such power the same amounts which I&M would have paid AEGCo under the terms of the I&M Power Agreement for such entitlement. The KPCo UPA ends in December 2022.

Cook Coal Terminal

Cook Coal Terminal, a division of OPCo, performs coal transloading services at cost for I&M. I&M recorded the cost of $32.6 million and $21.9 million for transloading services in Fuel Stock for the years ended December 31, 2012 and 2011, respectively.

Cook Coal Terminal also performs railcar maintenance services at cost for I&M. I&M paid OPCo $3.3 million and $3 million for railcar maintenance for the years ended December 31, 2012 and 2011, respectively. I&M recorded the cost of the railcar maintenance services in Fuel Stock.

SWEPCo Railcar Facility

SWEPCo operates a railcar maintenance facility in Alliance, Nebraska. The facility performs maintenance on its own railcars as well as railcars belonging to I&M. SWEPCo billed I&M $1.6 million and $2.9 million for railcar services provided in 2012 and 2011, respectively. These costs are recorded in Fuel Stock on the balance sheets.

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 NO_X emissions at certain generation plants in the AEP System. I&M recorded revenues from barging, transloading and other services for affiliates of $115.6 million and $105.4 million for the years ended December 31 2012 and 2011, respectively, in Revenues from Nonutility Operations.

Services Provided by AEP River Operations LLC

AEP River Operations LLC provides services for barge towing, chartering and general and administrative expenses to I&M. For the years ended December 31, 2012 and 2011, I&M recorded costs of $24 million each year for these activities as Expenses of Nonutility Operations.

Central Machine Shop

APCo operates a facility which repairs and rebuilds specialized components for the generation plants across the AEP System. I&M recorded billings from APCo of $1.3 million and $2.2 million as capital or maintenance expenses depending on the nature of the services received for the years ended December 31, 2012 and 2011, respectively. These billings are recoverable from customers.

Affiliate Railcar Agreement

The AEP East Companies, PSO and SWEPCo have an agreement providing for the use of each other's leased or owned railcars when available. The agreement specifies that the company using the railcar will be billed, at cost, by the company furnishing the railcar. I&M recorded these costs or reimbursements as costs or reduction of costs, respectively, in Fuel Stock on the balance sheets and such costs are recoverable from customers. The following table shows the net effect of the railcar agreement on the balance sheets:

	Years Ended December 31,	APCo	OPCo	PSO	SWEPCo
Payment of Costs:			(in thousands)		
	2012	$ 148	$ 889	$ 48	$ 843
	2011	91	1,190	80	787
Reimbursement of Costs:					
	2012	2	170	322	1,468
	2011	-	170	842	2,662

OVEC

AEP, OPCo and several nonaffiliated utility companies jointly own OVEC. As of December 31, 2012, AEP's and OPCo's ownership and investment in OVEC were as follows:

	December 31, 2012	
Company	**Ownership**	**Investment**
		(in thousands)
AEP	39.17 %	$ 3,978
OPCo	4.30 %	430
Total	43.47 %	$ 4,408

OVEC's owners, along with APCo and I&M, are members to an intercompany power agreement. Participants of this agreement are entitled to receive and obligated to pay for all OVEC generating capacity, approximately 2,200 MWs, in proportion to their respective power participation ratios. The aggregate power participation ratio of certain AEP utility subsidiaries, including APCo, I&M and OPCo, is 43.47%. The proceeds from the sale of power by OVEC are designed to be sufficient for OVEC to meet its operating expenses and fixed costs and provide a return on capital. In 2011, the intercompany power agreement was extended until June 2040.

AEP, OPCo and other nonaffiliated owners authorized environmental investments related to their ownership interests and OVEC's Board of Directors authorized capital expenditures totaling $1.4 billion in connection with the engineering and construction of FGD projects and the associated waste disposal landfills at OVEC's two generating plants. As of December 31, 2012, OVEC completed financing of $1.4 billion required for these environmental projects through debt issuances. As of December 31, 2012, one plant was operating with new environmental controls and the other plant is scheduled to be operational with new environmental controls during the second quarter of 2013.

Purchased Power from OVEC

I&M paid $49.2 million and $57.2 million for power purchased from OVEC for the years ended December 31, 2012 and 2011, respectively. The amounts are recoverable from customers and are included in Operation Expenses.

Purchases from OVEC under the Interconnection Agreement

In 2011, the parties to the Interconnection Agreement purchased power from OVEC to serve off-system sales and retail sales. These purchases are reported in Operation Expenses. The amounts recorded for I&M for the year ended December 31, 2011 was $12.9 million.

Sales and Purchases of Property

I&M had affiliated sales and purchases of electric property individually amounting to $100 thousand or more and sales and purchases of meters, transformers and transmission property. There were no gains or losses recorded on the transactions. The following table shows the sales and purchases, that were recorded in Utility Plant at net book value, for the years ended December 31, 2012 and 2011:

	Years Ended December 31, 2012	Years Ended December 31, 2011
	(in thousands)	
Sales	$ 3,296	$ 441
Purchases	285	3,678

Intercompany Billings

I&M and other AEP subsidiaries perform 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.

AEPSC

AEPSC provides certain managerial and professional services to AEP's subsidiaries. The costs of the services are based on a direct charge or on a prorated basis and billed to the AEP subsidiary companies at AEPSC's cost. AEPSC and its billings are subject to regulation by the FERC. I&M's total billings from AEPSC were $127.2 million and $126.5 million for the years ended December 31, 2012 and 2011, respectively.

13. 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 the annual composite depreciation rates by functional class:

Year	Nuclear	Steam	Hydro	Transmission	Distribution	General
				(in percentages)		
2012	1.3	2.4	2.5	1.5	2.5	9.6
2011	1.2	2.2	2.4	1.4	2.4	7.4

The composite depreciation rate generally includes a component for nonasset retirement obligation (non-ARO) removal costs, which is credited to accumulated depreciation. Actual removal costs incurred are charged to accumulated depreciation.

Asset Retirement Obligations (ARO)

I&M records ARO in accordance with the accounting guidance for "Asset Retirement and Environmental Obligations" for the retirement of certain ash disposal facilities and asbestos removal. I&M records ARO for the decommissioning of the Cook Plant. 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 its 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.

As of December 31, 2012 and 2011, I&M's ARO liability for nuclear decommissioning of the Cook Plant was $1.2 billion and $979 million, respectively. As of December 31, 2012 and 2011, the fair value of I&M's assets that are legally restricted for purposes of settling decommissioning liabilities totaled $1.4 billion and $1.3 billion, respectively. These assets are included in Other Special Funds.

The following is a reconciliation of the 2012 and 2011 aggregate carrying amounts of ARO related to nuclear decommissioning, ash disposal facilities and asbestos removal:

Year	ARO at January 1,	Accretion Expense	Liabilities Settled	Revisions in Cash Flow Estimates	ARO at December 31,
			(in thousands)		
2012	$ 1,013,122	$ 53,848	$ (806)	$ 126,149	$ 1,192,313
2011	963,029	51,308	(1,370)	155	1,013,122

Jointly-owned Electric Facilities

I&M has electric facilities that are jointly-owned with an affiliated company. Using its own financing, I&M is obligated to pay its share of the costs of any such jointly-owned facilities in the same proportion as its ownership interest. I&M's proportionate share of the operating costs associated with such 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:

			I&M's Share as of December 31, 2012		
Facility	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in thousands)	
Rockport Generating Plant (Unit No. 1) (a)	Coal	50.0 %	$ 762,737	$ 55,420	$ 456,436

			I&M's Share as of December 31, 2011		
Facility	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in thousands)	
Rockport Generating Plant (Unit No. 1) (a)	Coal	50.0 %	$ 759,033	$ 19,357	$ 443,857

(a) Operated by I&M.

14. COST REDUCTION PROGRAM

2012 Sustainable Cost Reduction

In April 2012, management initiated a process to identify strategic repositioning opportunities and efficiencies that will result in sustainable cost savings. Management selected a consulting firm to conduct an organizational and process evaluation and a second firm to evaluate current employee benefit programs. The process resulted in involuntary severances and is expected to be completed by the end of the first quarter of 2013. The severance program provides two weeks of base pay for every year of service along with other severance benefits.

I&M recorded a charge to expense primarily for severance benefits during 2012 related to the sustainable cost reductions initiative.

Expense Allocation from AEPSC	Incurred	Settled	Remaining Balance as of December 31, 2012
	(in thousands)		
$ 4,167	$ 1,511	$ (4,321)	$ 1,357

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	6,881,649,140	6,881,649,140
4	Property Under Capital Leases	23,562,126	23,562,126
5	Plant Purchased or Sold		
6	Completed Construction not Classified	234,867,469	234,867,469
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	7,140,078,735	7,140,078,735
9	Leased to Others		
10	Held for Future Use	6,294,968	6,294,968
11	Construction Work in Progress	341,062,641	341,062,641
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	7,487,436,344	7,487,436,344
14	Accum Prov for Depr, Amort, & Depl	3,494,503,152	3,494,503,152
15	Net Utility Plant (13 less 14)	3,992,933,192	3,992,933,192
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	3,361,883,239	3,361,883,239
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	132,615,751	132,615,751
22	Total In Service (18 thru 21)	3,494,498,990	3,494,498,990
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation	4,162	4,162
29	Amortization		
30	Total Held for Future Use (28 & 29)	4,162	4,162
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj		
33	Total Accum Prov (equals 14) (22,26,30,31,32)	3,494,503,152	3,494,503,152

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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)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)		
2	Fabrication		
3	Nuclear Materials	88,554,622	140,177,295
4	Allowance for Funds Used during Construction	9,154,251	4,004,419
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)	97,708,873	
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		
9	In Reactor (120.3)	124,839,783	110,095,121
10	SUBTOTAL (Total 8 & 9)	124,839,783	
11	Spent Nuclear Fuel (120.4)	255,621,386	6,316,389
12	Nuclear Fuel Under Capital Leases (120.6)	188,705,956	109,500,000
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	362,124,415	
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	304,751,583	
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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance	Line
Amortization (d)	Other Reductions (Explain in a footnote) (e)	End of Year (f)	No.
[redacted]	[redacted]		1
[redacted]			2
[redacted]	98,094,478	130,637,439	3
[redacted]	12,000,643	1,158,027	4
[redacted]			5
[redacted]	[redacted]	131,795,466	6
[redacted]	[redacted]		7
			8
	115,816,389	119,118,515	9
[redacted]	[redacted]	119,118,515	10
	36,987,146	224,950,629	11
122,140,800		176,065,156	12
-14,012,330	37,340,513	338,796,232	13
[redacted]	[redacted]	313,133,534	14
[redacted]	[redacted]		15
[redacted]	[redacted]		16
[redacted]	[redacted]		17
			18
			19
			20
			21
[redacted]	[redacted]		22

FOOTNOTE DATA

Schedule Page: 202 Line No.: 3 Column: e

Placed nuclear fuel into reactor

Schedule Page: 202 Line No.: 4 Column: e

Placed nuclear fuel into reactor

Schedule Page: 202 Line No.: 9 Column: e

Nuclear fuel removed from reactor and placed into spent fuel pool
$6,316,389

Reclassification of nuclear fuel from owned to leased due to sale/leaseback with 3rd party
$109,500,000

Schedule Page: 202 Line No.: 11 Column: e

Retirement of spent fuel

Schedule Page: 202 Line No.: 12 Column: b

Includes 2011 costs in connection with nuclear fuel leases:

Finance charges	$6,058,371
Administrative and legal	$ 204,000

Schedule Page: 202 Line No.: 12 Column: c

Reclassification of $109,500,000 of nuclear fuel from owned to leased due to sale/leaseback with 3rd party

Schedule Page: 202 Line No.: 12 Column: f

Includes 2012 costs in connection with nuclear fuel leases:

Finance charges	$6,681,715
Administrative and Legal	$ 51,000

Schedule Page: 202 Line No.: 13 Column: e

Retirement of spent fuel

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Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2012

ELECTRIC PLANT IN SERVICE (Accounts 101, 102, 103, 106)

1. Report below the original cost of plant in service in the same detail as in the current depreciation order.
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. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such amounts.
5. 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 distrubtions of 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) reversals of tentative distributions of prior year of unclassified retirements. Attach supplemental statement showing the account distributions of these tentative classifications in columns (c) and (d), including the

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	301 Organization	117,426	0
3	302 Franchises and Consents	19,866,098	0
4	303 Miscellaneous Intangible Plant	118,191,794	16,659,206
5	TOTAL Intangible Plant	**138,175,318**	**16,659,206**
6	2. PRODUCTION PLANT		
7	Steam Production Plant		
8	310.1 Land	11,323,112	0
9	310.2 Land Rights	222,069	0
10	311 Structures and Improvements	152,528,191	303,967
11	312 Boiler Plant Equipment	921,288,988	6,640,321
12	313 Engines and Engine-Driven Generators	0	0
13	314 Turbogenerator Units	188,388,420	427,604
14	315 Accessory Electric Equipment	87,730,992	532,021
15	316 Miscellaneous Power Plant Equipment	30,997,666	249,492
16	317 Asset Retirement Costs for Steam Production	25,867,785	
17	TOTAL Steam Production Plant	**1,418,347,223**	**8,153,405**
18	Nuclear Production Plant		
19	320.1 Land	1,879,588	0
20	320.2 Land Rights	0	0
21	321 Structures and Improvements	345,234,195	(17,997,805)
22	322 Reactor Plant Equipment	1,172,442,917	6,387,773
23	323 Turbogenerator Units	434,101,839	4,980,972
24	324 Accessory Electric Equipment	163,480,540	5,943,772

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report December 31, 2012

ELECTRIC PLANT IN SERVICE (Accounts 101, 102, 103, 106) (Continued)

reversals of the prior year's 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.

6. Show in column (f) reclassification 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. In showing the clearance of 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.

7. 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 requirements of these pages.

8. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchaser, 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 of such filing.

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
[redacted]					1
0	0	0	117,426	301	2
0	0	0	19,866,098	302	3
15,059,235	0	0	119,791,765	303	4
15,059,235	**0**	**0**	**139,775,289**		5
[redacted]					6
					7
0	0	0	11,323,112	310.1	8
0	0	0	222,069	310.2	9
229,256	0	0	152,602,902	311	10
2,571,087	0	(7,302)	925,350,920	312	11
0	0	0	0	313	12
459,458	0	7,302	188,363,868	314	13
141,603	0		88,121,410	315	14
46,857	0	0	31,200,301	316	15
	0	0	25,867,785	317	16
3,448,261	**0**	**0**	**1,423,052,367**		17
[redacted]					18
0	0	0	1,879,588	320.1	19
0	0	0	0	320.2	20
507,258	0	0	326,729,132	321	21
2,633,095	0	0	1,176,197,595	322	22
590,921	0	0	438,491,890	323	23
931,157	0	0	169,189,513	324	24

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2012

ELECTRIC PLANT IN SERVICE (Accounts 101, 102, 103, 106) (Continued)

Line No.	Account (a)	Balance at Beginning of Year (b)	Addition (c)
25	325 Miscellaneous Power Plant Equipment	170,795,917	7,247,756
26	326 Asset Retirement Costs for Nuclear Production	151,397,582	126,158,452
27	TOTAL Nuclear Production Plant	**2,439,332,578**	**132,720,920**
28	Hydraulic Production Plant		
29	330.1 Land	510,360	0
30	330.2 Land Rights	196,186	0
31	331 Structures and Improvements	3,215,591	196,808
32	332 Reservoirs, Dams and Waterways	19,043,109	1,126,291
33	333 Water Wheels, Turbines and Generators	16,184,266	44,498
34	334 Accessory Electric Equipment	5,278,302	7,487
35	335 Miscellaneous Power Plant Equipment	2,089,990	124,675
36	336 Roads, Railroads and Bridges	853	0
37	337 Asset Retirement Costs for Hydraulic Production	242,144	0
38	TOTAL Hydraulic Production Plant	**46,760,801**	**1,499,759**
39	Other Production Plant		
40	340.1 Land	0	0
41	340.2 Land Rights	0	0
42	341 Structures and Improvements	0	0
43	342 Fuel Holders, Products and Accessories	0	0
44	343 Prime Movers	0	0
45	344 Generators	0	0
46	345 Accessory Electric Equipment	0	0
47	346 Miscellaneous Power Plant Equipment	0	0
48	347 Asset Retirement Costs for Other Production	0	0
49	TOTAL Other Production Plant	**0**	**0**
50	TOTAL Production Plant	**3,904,440,602**	**142,374,084**
51	3. TRANSMISSION PLANT		
52	350.1 Land	6,899,232	460,756
53	350.2 Land Rights	51,569,473	1,986,621
54	352 Structures and Improvements	20,760,148	295,054
55	353 Station Equipment	577,428,782	48,157,897
56	354 Towers and Fixtures	222,210,262	602,627
57	355 Poles and Fixtures	104,703,374	6,234,560
58	356 Overhead Conductors and Devices	233,272,053	3,301,524
59	357 Underground Conduit	2,215,165	111,173
60	358 Underground Conductors and Devices	5,179,563	566,678

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2012

ELECTRIC PLANT IN SERVICE (Accounts 101, 102, 103, 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
1,469,446	0	0	176,574,227	325	25
0	0	0	277,556,034	326	26
6,131,877	**0**	**0**	**2,566,617,979**		27
					28
0	0	0	510,360	330.1	29
0	0	0	196,186	330.2	30
73,247	0	0	3,339,152	331	31
101,182	0	0	20,068,218	332	32
7,067	0	0	16,221,697	333	33
2,685	0	0	5,283,104	334	34
0	0	0	2,214,665	335	35
0	0	0	853	336	36
0	0	0	242,144	337	37
184,181	**0**	**0**	**48,076,379**		38
					39
0	0	0	0	340.1	40
0	0	0	0	340.2	41
0	0	0	0	341	42
0	0	0	0	342	43
0	0	0	0	343	44
0	0	0	0	344	45
0	0	0	0	345	46
0	0	0	0	346	47
0	0	0	0	347	48
0	**0**	**0**	**0**		49
9,764,319	**0**	**0**	**4,037,746,725**		50
					51
767	0	0	7,359,221	350.1	52
0	0	0	53,556,094	350.2	53
38,425	0	0	21,016,777	352	54
6,949,813	0	(696,358)	617,940,508	353	55
240,031	0	203,339	222,776,197	354	56
281,649	0	(207,527)	110,448,758	355	57
59,936	0		236,513,641	356	58
1	0	0	2,326,337	357	59
6,068	0	0	5,740,173	358	60

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report December 31, 2012

ELECTRIC PLANT IN SERVICE (Accounts 101, 102, 103, 106) (Continued)

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)
61	359 Roads and Trails	349,749	0
62	359.1 Asset Retirement Costs for Transmission Plant	0	0
63	TOTAL Transmission Plant	**1,224,587,801**	**61,716,890**
64	4. DISTRIBUTION PLANT		
65	360.1 Land	4,258,378	116,951
66	360.2 Land Rights	12,225,876	93,881
67	361 Structures and Improvements	8,965,576	314,879
68	362 Station Equipment	179,817,258	11,323,562
69	363 Storage Battery Equipment	5,488,476	2,010
70	364 Poles, Towers and Fixtures	216,164,336	7,531,036
71	365 Overhead Conductors and Devices	289,169,259	22,207,000
72	366 Underground Conduit	63,142,096	1,925,335
73	367 Underground Conductors and Devices	177,385,971	7,030,433
74	368 Line Transformers	257,010,698	16,222,566
75	368.1 Capacitors	0	
76	369 Services	145,846,333	7,007,734
77	370 Meters	83,454,995	25,263,984
78	371 Installations on Customers' Premises	20,251,231	1,893,763
79	372 Leased Property on Customers' Premises	0	
80	373 Street Lighting and Signal Systems	18,274,620	380,006
81	374 Asset Retirement Costs for Distribution Plant	0	0
82	TOTAL Distribution Plant	**1,481,455,103**	**101,313,140**
83	5. GENERAL PLANT		
84	389.1 Land	2,100,201	0
85	389.2 Lands Rights	178,388	0
86	390 Structures and Improvments	52,741,561	1,190,672
87	391 Office Furniture and Equipment	5,969,972	142,235
88	391.1 Computers / Computer Related Equipment	0	0
89	392 Transportation Equipment	0	0
90	393 Stores Equipment	36,621	4,228
91	394 Tools, Shop and Garage Equipment	9,319,542	922,501
92	395 Laboratory Equipment	292,955	45,564
93	396 Power Operated Equipment	544,756	10
94	397 Communication Equipment	24,534,946	3,262,511
95	398 Miscellaneous Equipment	7,617,401	365,873
96	SUBTOTAL	**103,336,343**	**5,933,594**

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report December 31, 2012

ELECTRIC PLANT IN SERVICE (Accounts 101, 102, 103, 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
0	0	0	349,749	359	61
0	0	0	0	359.1	62
7,576,690	**0**	**(700,546)**	**1,278,027,455**		63
					64
3,146	0	0	4,372,183	360.1	65
0	0	0	12,319,757	360.2	66
80,995	0	0	9,199,460	361	67
1,874,419	0	0	189,266,401	362	68
3,827	0	0	5,486,659	363	69
1,058,877	0	4,188	222,640,683	364	70
3,318,798	0	0	308,057,461	365	71
648,158	0	0	64,419,273	366	72
789,027	0	0	183,627,377	367	73
3,519,076	0	0	269,714,188	368	74
0	0	0	0	368.1	75
828,985	0	0	152,025,082	369	76
16,708,047	0	0	92,010,932	370	77
547,312	0	0	21,597,682	371	78
0	0	0	0	372	79
236,311	0	0	18,418,315	373	80
0	0	0	0	374	81
29,616,978	**0**	**4,188**	**1,553,155,453**		82
					83
0	0	0	2,100,201	389.1	84
0	0	0	178,388	389.2	85
199,208	0	0	53,733,025	390	86
7,662	0	0	6,104,545	391	87
0	0	0	0	391.1	88
0	0	0	0	392	89
0	0	0	40,849	393	90
83,782	0	0	10,158,261	394	91
458	0	0	338,061	395	92
0	0	0	544,766	396	93
1,340,061	0	0	26,457,396	397	94
0	0	0	7,983,274	398	95
1,631,171	**0**	**0**	**107,638,766**		96

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2012

ELECTRIC PLANT IN SERVICE (Accounts 101, 102, 103, 106) (Continued)

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)
97	399 Other Tangible Property	0	0
98	399.1 Asset Retirement Costs for General Plant	186,379	0
99	TOTAL General Plant	**103,522,722**	**5,933,594**
100	TOTAL (Accounts 101 and 106)	**6,852,181,546**	**327,996,914**
101			
102	102 Electric Plant Purchased	0	0
103	(Less) 102 Electric Plant Sold	0	0
104	103 Experimental Plant Unclassified	0	0
105	TOTAL Electric Plant in Service *(Total of lines 94 thru 98)*	**6,852,181,546**	**327,996,914**

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report December 31, 2012

ELECTRIC PLANT IN SERVICE (Accounts 101, 102, 103, 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
0	0	0	0	399	97
13,458	0	0	172,921	399.1	98
1,644,629	**0**	**0**	**107,811,687**		99
63,661,851	**0**	**0**	**7,116,516,609**		100
					101
0	0	0	0	102	102
0	0	0	0		103
0	0	0	0	103	104
63,661,851	**0**	**0**	**7,116,516,609**		105

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31,2012

FOOTNOTE DATA

Page Number (a)	Line Number (b)	Column Number (c)	Comments (d)
207	53	g	The investment and related accumulated depreciation in Generation Step-Up Units (GSUs) in plant accounts 352-353 included in I&M's generation formula rates are identified by a query of the plant accounting system.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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				
3	Generating Plant Project Site (0110)	09/01/75		4,408,182
4				
5	Tanners Creek Generating Plant Units 1-4 (0105)	09/01/75		360,235
6				
7	Rockport Generating Plant Unit 1 (0111)	11/01/84		1,034,109
8				
9				
10	Items under $250,000			486,519
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22	Items under $250,000			5,923
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			6,294,968

Schedule Page: 214 Line No.: 46 Column: d

The generation assets in Electric Plant Held for Future use included in I&M's generation formula rates are identified by a query of the plant accounting system.

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2012

PLANT ACQUISITION ADJUSTMENTS AND ACCUMULATED PROVISION FOR AMORTIZATION OF PLANT ACQUISITION ADJUSTMENTS (Accounts 114 & 115)

1. Report the particulars called for concerning acquisition adjustments.
2. Provide a subheading for each account and list thereunder the information called for, observing the instructions below.
3. Explain each debit and credit during the year, give reference to any Commission orders or other authorizations concerning such amounts, and show contra account debited or credited.
4. For acquisition adjustments arising during the year state the name of the company from which the property was acquired, date of transaction, and date journal entries clearing Account 102, Plant Purchased or Sold, were filed with the Commission.
5. In the blank space at the bottom of the schedule, explai the plan of disposition of any acquisition adjustments not currently being amortized.
6. Give date Commission authorized use of Account 115.

Line No.	Description (a)	Balance Beginning of Year (b)	Debits (c)	CREDITS Contra Acct. (d)	CREDITS Amount (e)	Balance End of Year (f)
1	Account 114					
2	None					
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15	Account 115					
16	None					
17						
18						
19						
20						

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Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2012

CONSTRUCTION WORK IN PROGRESS AND COMPLETED CONSTRUCTION NOT CLASSIFIED - ELECTRIC (Accounts 107 and 106)

1. Report below descriptions and balances at end of year of projects in process of construction and completed construction not classified for projects actually in service. For any substantial amounts of completed construction not classified for plant actually in service explain the circumstances which have prevented final classification of such amounts to prescribed primary accounts for plant in service.
2. The information specified by this schedule for Account 106, Completed Construction Not Classified-Electric, shall be furnished even though this account is included in the schedule, Electric Plant in Service, pages 204-211, according to a tentative classification by primary accounts.
3. Show items relating to "research and development" projects last under a caption Research and Development (See Account 107, Uniform System of Accounts).
4. Minor projects may be grouped.

Line No.	Description of Project (a)	Construction Work in Progress-Electric (Account 107) (b)	Completed Construction Not Classified-Electric (Account 106) (c)	Estimated Additional Cost of Project (d)
1	Forestry IM IN D Base R W	8,887,234		
2	Forestry IM MI D Base R W	3,263,738		
3	TP2008FW4-TWIN BR-E ELK 138KV	1,701,455		2,233,386
4	IM/IN/Ellison Sta - Purchase	1,970,412		
5	IM/IN/East Side Station D-Sta	1,804,795		
6	I&M Next Generation Radio Syst	13,921,282		106,545
7	U1 Control Room HVAC Chiller	1,344,515		4,397,838
8	Ice Cndsr Glycol Chiller Rplmt	6,480,060		10,137,706
9	U2 Control Room Annunc. Replac	3,006,500		3,506,511
10	U1 Control Room Annunc Replace	4,599,269		2,544,637
11	Unit 2 PPC Replacement	4,091,099		4,415,596
12	Unit 1 PPC Replacement	8,689,044		2,717,483
13	U1 Steam Generator WL Controls	1,046,077		7,119,520
14	U2 SG Water Level Controls	1,130,065		6,993,223
15	Unit 1 Refueling Equipment	1,033,868		11,318,623
16	TR1ABCD Replacement	4,027,027		3,540,811
17	TR2ABCD Replacement - U2	1,803,626		4,988,712
18	U2 East CTS Hx Replacement	1,120,789		5,433,879
19	U1 East CTS Hx Replacement	1,371,846		6,574,452
20	U2 FW Heaters LP	6,310,486		15,002,710
21	U2 Feedwater Htrs HP	7,853,459		28,545,570
22	U1 HP FW Heaters Replac	3,320,235		37,074,902
23	Cyber Attacks Process LAN	4,877,434		805,820
24	U2 Internal Lift Rig Upgrades	1,017,594		
25	CK U1 Sec Sys Wtr Chem Upgrade	11,247,876		7,513,983
26	U2 Sec Sys Wtr Chem Upgrade	10,871,595		7,513,983
27	EPU/LCM Mods	3,808,551		180,441,485
28	U2 MSR FW Heater Digital Cnt	3,573,023		12,609,132
29	U2 MSR Valve Piping Optimizat	2,562,880		5,019,356
30	U2 Control Room Chiller Rplmnt	1,606,017		3,191,051
31	U1 CTS Ht Exchanger - West	4,499,484		4,249,250
32	U2 CTS Heat Exchanger - West	1,121,443		6,024,966
33	316(b) Compliance (Tunnel)	7,829,503		445,855,898
34	Mod to Address Screenhse HELB	6,060,983		3,512,212
35	**TOTAL**	**341,062,641**	**234,867,469**	**1,299,734,331**

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report December 31, 2012

CONSTRUCTION WORK IN PROGRESS AND COMPLETED CONSTRUCTION NOT CLASSIFIED - ELECTRIC (Accounts 107 and 106)

1. Report below descriptions and balances at end of year of projects in process of construction and completed construction not classified for projects actually in service. For any substantial amounts of completed construction not classified for plant actually in service explain the circumstances which have prevented final classification of such amounts to prescribed primary accounts for plant in service.
2. The information specified by this schedule for Account 106, Completed Construction Not Classified-Electric, shall be furnished even though this account is included in the schedule, Electric Plant in Service, pages 204-211, according to a tentative classification by primary accounts.
3. Show items relating to "research and development" projects last under a caption Research and Development (See Account 107, Uniform System of Accounts).
4. Minor projects may be grouped.

Line No.	Description of Project (a)	Construction Work in Progress-Electric (Account 107) (b)	Completed Construction Not Classified-Electric (Account 106) (c)	Estimated Additional Cost of Project (d)
1	U2 LP and HP Turbine	46,142,074		100,445,806
2	U1 RCP Seal Replacement	2,102,737		848,843
3	U2 RCP Seal Replacement (SHIEL	2,091,141		848,577
4	Defensive Strategy Enhancement	21,876,024		11,225,688
5	Fish Deterrrent Sys Cable Rpl	1,308,331		
6	RK U0 FGD Landfill	2,709,683		14,157,574
7	RK U1 DFGD w/ FF	21,426,371		162,258
8	RK U1 SCR Project	6,602,971		117,579,350
9	RK 1&2 DSI FGD	3,934,451		84,130,884
10	RKP05CIIM Horiz RH ReplaceU1	2,947,291		9,678,521
11	RK U2 CoolingTower Fill Rplcmt	1,596,651		2,218,900
12	RK10 CI U2 Economizer	9,863,596		13,017,831
13	RK11U0 IP Turb Assem for U2	3,864,258		1,132,354
14	T/I&M/Line Rebuild	1,638,169		
15	TL/I&M/IN/South Bend - Colfax	1,580,707		240,239
16	T/I&M/Line Rehab/Replace	1,866,880		
17	T/I&M/Purchase/Rebuild Maj Eqp	1,352,447		
18	TC411 HP HEATER REPLACEMENT	1,453,472		1,902,798
19	T/I&M/IN/Elkhart 34.5 kV Upgra	2,381,926		3,086,014
20	TL/I&M/IN/Rockport-Jefferson 7	5,470,125		2,902,190
21	WS-CI-IMPCo-G PPB	2,281,568		
22	RP-CI-IMPCo-G NMIB	7,425,875		
23	ET-CI-IMPCo-T ASSET IMP	3,408,776		
24	Ed-Ci-Impco-D Ast Imp	3,209,281		
25	Ed-Ci-Impco-D Cust Serv	1,508,366		
26	Other Minor Projects Under $1,000,000	33,166,206		102,767,265
27				
28				
29				
30				
31	Completed Construction Not Classified		234,867,469	
32				
33				
34				
35	**TOTAL**	**341,062,641**	**234,867,469**	**1,299,734,331**

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Co.	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2012

CONSTRUCTION OVERHEADS - ELECTRIC

1. List in columns (a) the kinds of overheads according to the titles used by the respondent. Charges for outside professional services for engineering fees and management or supervision fees capitalized should be shown as separate items.
2. On page 218 furnish information concerning construction overheads.
3. A respondent should not report "none" to this page if no overhead apportionments are made, but rather should explain on page 218 the accounting procedures employed and the amounts of engineering, supervision and administrative costs, etc., which are directly charged to construction.
4. Enter on this page engineering, supervision, administrative, and allowance for funds used during construction, etc., which are first assigned to a blanket work order and then prorated to construction jobs.

Line No.	Description of Overhead (a)	Total Amount Charged for the Year (b)
1	Fossil/Hydro Construction Overheads	4,203,884
2		
3	Nuclear Construction Overheads	6,495,754
4		
5	Transmission Construction Overheads	3,808,601
6		
7	Distribution Construction Overheads	18,058,175
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
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25		
26		
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36		
37		
38		
39	**TOTAL**	**32,566,414**

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Co.	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2012

GENERAL DESCRIPTION OF CONSTRUCTION OVERHEAD PROCEDURE

1. For each construction overhead explain: (a) the nature and extent of work, etc., the overhead charges are intended to cover, (b) the general procedure for determining the amount capitalized, (c) the method of distribution to construction jobs, (d) whether different rates are applied to different types of construction, (e) basis of differentiation in rates for different types of construction, and (f) whether the overhead is directly or indirectly assigned.
2. Show below the computation of allowance for funds used during construction rates, if those differ from the overall rate of return authorized by the Michigan Public Service Commission.

1. The company has certain administrative, supervisory and engineering personnel whose costs cannot, without undue burden and refinement, be classified directly to projects. Construction overheads are used to allocate these indirect costs to individual projects of this kind. The construction overhead rate calculated is applied to applicable capital work order charges.

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2012

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT *(Account 108 & 110)*

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 11, column (c), and that reported for electric plant in service, pages 202-204A, column (d), excluding retirements of non-depreciable property.
3. Accounts 108 and 110 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 cost 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.

Section A. Balances and Changes During Year

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)
1	Balance Beginning of Year	3,296,683,179	3,296,679,098	4,081	
2	Depreciation Prov. for Year, Charged to				
3	(403) Depreciation Expense	119,838,503	119,838,422	81	
4	(403.1) Decommissioning Expense	4,030,977	4,030,977	0	
5	(413) Exp. Of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing				
7	Other Clearing Accounts				
8	Other Accounts (Specify):	1,361,500	1,361,500	0	
9					
10	TOTAL Deprec. Prov. For Year *(Enter Total of Lines 3 thru 9)*	**125,230,980**	125,230,899	81	
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	49,935,372	48,332,611	1,602,761	
13	Cost of Removal	35,276,044	35,357,567	(81,523)	
14	Salvage (Credit)	30,264,079	28,742,841	1,521,238	
15	TOTAL Net Chrgs. For Plant Ret. *(Enter Total of lines 12 thru 14)*	**54,947,337**	54,947,337	0	
16	Net Earnings of Decommissioning Funds				
17	Other Debit or Credit Items (Described)				
18	Retirement WIP	0	0		
19	Asbestos ARO	(5,128,437)	(5,128,437)		
20	Transfer between Accounts 108 & 111	49,016	49,016	0	
21	Balance End of Year *(Enter total of lines 1, 10, 15, 16 & 17)*	**3,361,887,401**	3,361,883,239	4,162	

Section B. Balances at End of Year According to Functional Classifications

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)
22	Steam Production	850,086,256	850,086,256	0	
23	Nuclear Production	1,441,931,518	1,441,931,518		
24	Hydraulic Production-Conventional	26,044,331	26,044,331		
25	Hydraulic Production-Pumped Storage	0	0		
26	Other Production	0	0		
27	Transmission	537,188,312	537,184,150	4,162	
28	Distribution	479,335,470	479,335,470		
29	General	27,301,514	27,301,514		
30	TOTAL (Enter total of lines 20 thru 28)	**3,361,887,401**	3,361,883,239	4,162	

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2012

FOOTNOTE DATA

Page Number (a)	Line Number (b)	Column Number (c)	Comments (d)
219	8	C	Abestos depreciation and accretion expense in account 1080013 - $1,377,340 Amortize Indiana jurisdictional portion of reg asset for ash ponds ARO's - ($6,677) Adjustment for Bell howell Inserter depreciation expense billed by AEPSC - ($9,163) Total $1,361,500

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Name of Respondent	This Report Is:	Date of Report	Year of Report
INDIANA MICHIGAN POWER COMPANY	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2012

NONUTILITY PROPERTY (Account 121)

1. Give a brief description and state the location of nonutility property included in Account 121.
2. Designate with a double asterisk any property which is leased to another company. State name of lessee and whether lessee is an associated company.
3. Furnish particulars (details) concerning sales, purchases, or transfers of Nonutility Property during the year.
4. List separately all property previously devoted to public service and give date of transfer to Account 121, Nonutility Property.
5. Minor items (5% of the Balance at the End of the Year for Account 121 or $100,000, whichever is less) may be grouped by (1) previously devoted to public service, or (2) other nonutility property.

Line No.	Description and Location (a)	Balance at Beginning of Year (b)	Purchases, Sales Transfers, etc. (c)	Balance at End of Year (d)
1	Water Transportation Facilities, headquartered at St Louis, MO	25,485,898	1,857,791	27,343,689
2	Office Building Leasehold Improvements, One Summit Square, Fort Wayne, IN	2,695,099	0	2,695,099
3	Land, purchased in connection with Jefferson West 765kv Corridor, Jefferson County, IN	164,576	0	164,576
4	Land, Prosperity East 138kv Corridor, Madison County, IN	102,956	0	102,956
5	Land near Tanners Creek Plant, Lawrenceburg, IN	146,364	0	146,364
6	Land for Butler Center Substation	110,789	0	110,789
7	Land for Fuson Substation, Delaware County, IN	102,430	0	102,430
8	Minor items previously devoted to public service	8,174	0	8,174
9	Minor items - other nonutility property	460,572	0	460,572
	TOTAL	29,276,858	1,857,791	31,134,649

ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION OF NONUTILITY PROPERTY (Account 122)

Report below the information called for concerning depreciation and amortization of nonutility property.

Line No.	Item (a)	Amount (b)
1	Balance, Beginning of Year	14,149,385
2	Accruals for Year, Charged to	
3	(417) Income from Nonutility Operations	806,624
4	(418) Nonoperating Rental Income	44,884
5	Other Accounts (Specify):	
6	Accounts 227 and 243	1,135,105
7	TOTAL Accruals for Year (Enter Total of lines 3 thru 6)	1,986,613
8	Net Charges for Plant Retired:	
9	Book Cost of Plant Retired	0
10	Cost of Removal	0
11	Salvage (Credit)	0
12	TOTAL Net Charges (Enter Total of lines 9 thru 11)	0
13	Other Debit or Credit Items (Describe):	
14	Reclassifications from/to Other Accounts	(84,595)
15	Balance, End of Year (Enter Total of lines 1, 7, 12, and 14)	16,051,403

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2012

1. Report below the investments in Accounts 123, *Investments in Associated Companies*, 124, *Other Investment*, and 136, *Temporary Cash Investments.*
2. Provide a subheading for each account and list thereunder the information called for:
(a) Investment in securities - List and describe each security owned, giving name of user, date acquired and date of maturity. For bonds, also give principal amount, date of issue, maturity, and interest rate. For capital stock (including capital stock of respondent reacquired under a definite plan for resale pursuant to authorization by the Board of Directors, and included in Account 124, *Other Investments),* state number of shares, class, and series of stock. Minor investments may be grouped by classes. Investments included in Account 136, *Temporary Cash Investments*, also may be grouped by classes.
(b) Investment Advances-Report separately for each person or company the amounts of loans or investment advances which are properly includable in Account 123. Advances subject to current repayment should be included in Accounts 145 and 146. With respect to each advance, show whether the advance is a note or an open account. Each note should be

Line No.	Description of Investment (a)	Book Cost at Beginning of Year *(If book cost is different from cost to respondent, give cost to respondent in a footnote and explain difference)* (b) Original Cost	Book Value	Purchases or from Improvement Disposed of (c)
1	Account 123 - Investment in Associated Companies		(see pp. 224-225)	
2				
3	Account 124 - Other Investments			
4	Franklin Real Estate and Indiana Franklin - Land Purchase Contracts			
5	- Michigan		266,733	0
6	- Other States		10,523,251	0
7				
8	Private Fuel Storage LLC		6,280,314	0
9				
10	Fiber Optic Agreements with AEP Communications, Kentucky Data		4,971,254	0
11	Link, Inc, and Citynet Fiber Network, Inc			
12				
13	Speculative Allowance Inventory			
14	- NOx		26	0
15	- SO2		0	0
16	- CO2		0	0
17				
18	Shell Building Loan		15,000	0
19				
20	Other Miscellaneous Investments		8,039	0
21				
22	Depreciation Reserve		(16,979)	16,979
23				
24	Ripley Land Purchase		745,386	
25				
26	Total Account 124		22,793,024	16,979
27				
28	Account 136 - Temporary Cash Investments			
29				
30				
31	Grand Total		22,793,024	16,979

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2012

INVESTMENTS (Accounts 123, 124, 136) (Cont'd)

listed giving date of issuance, maturity date, and specifying whether note is a renewal. Designate any advances due from officers, directors, stockholders, or employees. Exclude amounts reported on page 229.
3. For any securities, notes or accounts that were pledged designate with an asterisk such securities, notes, or accounts and in a footnote state the name of pledgee and purpose of the pledge.
4. 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.
5. Report in column (g) interest and dividend revenues from investments including such revenues from securities disposed of during the year.
6. 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 any dividend or interest adjustment includible in column (g).

Sales or Other Dispositions During Year (d)	Principal Amount or No. of Shares at End of Year (e)	Book Cost at End of Year (*If book cost is different from cost to respondent, give cost to respondent in a footnote and explain difference*) (f) Original Cost	(f) Book Value	Revenues for Year (g)	Gain of Loss from Improvement Disposed of (h)	Line No.
						1
						2
						3
						4
0			266,733			5
233,379			10,289,872			6
						7
6,280,314			0			8
						9
150,011			4,821,243			10
						11
						12
						13
9			17			14
0			0			15
0			0			16
						17
0			15,000			18
						19
0			8,039			20
						21
0			0			22
						23
0			745,386			24
						25
6,663,713			16,146,290			26
						27
						28
						29
						30
6,663,713	0	0	16,146,290	0	0	31

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.
2. Provide a subheading for each company and List there under 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.

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	Blackhawk Coal Company, Inc.	09-01-80		
2	Common Stock			25,324,000
3	Cash Capital Contribution			
4	Equity in Earnings			-230,765
5	Investment in Subsidiary AOCI			-1,629,740
6	Subtotal			23,463,495
7				
8	Price River Coal Company, Inc.	12-01-65		
9	Common Stock			27,275
10	Subtotal			27,275
11				
12				
13				
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41				
42	Total Cost of Account 123.1 $ 146,936,960		TOTAL	23,490,770

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

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 form investments, including such revenues form 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 difference 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

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)	Line No.
				1
		25,324,000		2
				3
125,886		-104,879		4
		-1,521,319		5
125,886		23,697,802		6
				7
				8
		27,275		9
		27,275		10
				11
				12
				13
				14
				15
				16
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125,886		23,725,077		42

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2012

NOTES AND ACCOUNTS RECEIVABLE SUMMARY FOR BALANCE SHEET

Show separately by footnote the total amount of notes and accounts receivable from directors, officers, and employees included in Notes Receivable (Account 141) and Other Accounts Receivable (Account 143).

Line No.	Accounts (a)	Balance Beginning of Year (b)	Balance End of Year (c)
1	Notes Receivable (Account 141)	0	0
2	Customer Accounts Receivable (Account 142)	72,346,209	61,689,515
3	Other Accounts Receivable (Account 143 & 171 & 172) (Disclose any capital stock subscriptions received)	25,518,048	16,069,074
4	TOTAL	**97,864,257**	**77,758,589**
5	Less: Accumulated Provision for Uncollectible Accounts-Cr. (Account 144)	1,749,514	229,449
6	TOTAL, Less Accumulated Provision for Uncollectible Accounts	**96,114,743**	**77,529,140**
7			
8	Account 143 includes employee receivables of $741,352 @		
9	12/31/11 and $712,666 @ 12/31/12 related to a 2001 biweekly		
10	payroll conversion that will be collected when the employees leave		
11	the company.		
12			
13			
14			

ACCUMULATED PROVISION FOR UNCOLLECTIBLE ACCOUNT-CR. (Account 144)

1. Report below the information called for concerning this accumulated provision.
2. Explain any important adjustments of subaccounts.
3. Entries with respect to officers and employees shall not include items for utility services.

Line No.	Item (a)	Utility Customers (b)	Merchandise Jobbing and Contract Work (c)	Officers and Employees (d)	Other (e)	Total (f)
1	Balance beginning of year		208,970		1,540,544	1,749,514
2	Prov. For uncollectibles for current year		20,479		0	20,479
3	Account written off (less)		0		1,540,544	1,540,544
4	Charged to other accounts					0
5	Adjustments (explain):					0
	Adjustment to Beginning Balance		0		0	0
6	Balance end of year	0	229,449	0	0	**229,449**
7						
8						
9						
10						
11						

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Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2012

RECEIVABLES FROM ASSOCIATED COMPANIES (Accounts 145, 146)

1. Report particulars of notes and accounts receivable from associated companies* at end of year.
2. Provide separate headings and totals for Accounts 145, Notes Receivable from Associated Companies, and 146, Accounts Receivable from Associated Companies, in addition to a total for the combined accounts.
3. For notes receivable, list each note separately and state purpose for which received. Show also in column (a) date of note, date of maturity and interest rate.
4. If any note was received in satisfaction of an open account, state the period covered by such open account.
5. Include in column (f) interest recorded as income during the year including interest on accounts and notes held any time during the year.
6. Give particulars of any notes pledged or discounted, also of any collateral held as guarantee of payment of any note or account.

* NOTE: "Associated companies" means companies or persons that, directly or indirectly, through one or more intermediaries, control, or are controlled by, or are under common control with, the account company. This includes related parties.

"Control" (including the terms "controlling," "controlled by," and "under common control with") means the possession, directly or indirectly, of the power to direct or cause the direction of the management and policies of a company, whether such power is exercised through one or more intermediary companies, or alone, or in conjunction with, or pursuant to an agreement, and whether such power is established through a majority or minority ownership or voting of securities, common directors, officers or stockholders, voting trusts, holding trusts, associated companies, contract or any other direct or indirect means.

Line No.	Particulars (a)	Balance Beginning of Year (b)	Totals for Year: Debits (c)	Totals for Year: Credits (d)	Balance End of Year (e)	Interest for Year (f)
1	Account 145					
2	AEP Utility Funding LLC	90,442,321	643,393,174	630,216,131	103,619,364	901,201
3						
4	Account 146					
5						
6	AEP Generating Company	27,082,813	340,089,787	335,454,893	31,717,707	
7	AEP Memco	2,076,234	5,622,221	5,543,213	2,155,242	
8	AEP Pro Serv	1,284	2,746	4,030	0	
9	AEP Service Corporation	32,352,051	1,235,469,993	1,252,334,852	15,487,192	
10	AEP System Pool (AEPSC)	15,495,055	631,814,203	635,573,796	11,735,462	
11	AEP T&D Services, LLC	(0)	5,703	5,703	(0)	
12	AEP Texas Central	(11,428)	142,616	123,722	7,466	
13	AEP Texas North	27,416	1,299,708	1,314,532	12,592	
14	AEP Utilities, Inc.	1,512,625	177,300,628	178,163,383	649,870	
15	AEP Utility Funding LLC	(0)	313	274	39	
16	American Electric Power Co	2,423,125	303,751,450	306,164,240	10,335	
17	Appalachian Power Co	3,810,385	58,482,452	59,816,098	2,476,739	
18	Blackhawk Coal Company	5,062	40,587	41,886	3,763	
19	Cardinal Operating	62,402	4,485,086	4,182,857	364,631	
20	Cook Coal Terminal	6,655	518,973	501,137	24,491	
21	CSW Energy, Inc.	(0)	1,416,887	1,416,711	176	

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2012

RECEIVABLES FROM ASSOCIATED COMPANIES (Accounts 145, 146)

Line No.	Particulars (a)	Balance Beginning of Year (b)	Totals for Year: Debits (c)	Totals for Year: Credits (d)	Balance End of Year (e)	Interest for Year (f)
1	Kentucky Power Co	12,722	867,548	871,256	9,014	
2	Kingsport Power Co	2,768	9,937	12,147	558	
3	Ohio Power Co	2,603,440	68,335,680	64,723,422	6,215,698	
4	Public Service Co of Ok	74,759	610,304	644,959	40,104	
5	Southwestern Power Co	72,561	5,561,807	5,469,179	165,189	
6	Wheeling Power Co	795	25,346	25,693	448	
7	United Sciences	0	3,395	3,390	5	
8	AEP Holdings	(10,000)	0	0	(10,000)	
9	AEP Energy Services	0	2,585	2,215	370	
10	AEP Wind Holding Co	0	953	825	128	
11	Various Transmission	901,500	70,090,654	64,638,726	6,353,428	
12	AEP Transmission	50,615	1,629,273	1,679,838	50	
13	AEP Resources Inc.	0	58	49	9	
14	AEP C&I Company LLC	0	1,241	1,062	179	
15	AEP Investments	0	95	81	14	
16						
17						
18						
19						
20						
21						
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30						
31						
32						
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35						
36						
37						
38						
39						
40						
41						
42						
43						
44	TOTAL	178,995,161	3,550,975,402	3,548,930,300	181,040,263	901,201

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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)	51,129,732	50,571,903	Electric
2	Fuel Stock Expenses Undistributed (Account 152)	1,849,711	2,834,549	Electric
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	52,245,285	71,119,095	Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	92,255,701	78,369,002	Electric
8	Transmission Plant (Estimated)	529,602	1,954,137	Electric
9	Distribution Plant (Estimated)			Electric
10	Regional Transmission and Market Operation Plant (Estimated)	1,083,329	891,736	
11	Assigned to - Other (provide details in footnote)	124,743	52,111	Electric
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	146,238,660	152,386,081	Electric
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)	3,057,394	3,162,314	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 (Per Balance Sheet)	202,275,497	208,954,847	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) X An Original (2) _ A Resubmission	/ /	2012/Q4

FOOTNOTE DATA

Schedule Page: 227 Line No.: 11 Column: b

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

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2012

Production Fuel and Oil Stocks (Included in Account 151)

1. Report below the information called for concerning production fuel and oil stock.
2. Show quantities in tons 0f 2000 lb. Barrels (42 gals.) or Mcf., whichever unit of quantity is applicable.
3. Each kind of coal or oil should be shown separately.
4. If the respondent obtained any of its fuel from its own coal mines or oil or gas lands or leases or from affiliated companies, a statement should be submitted showing the quantity of such fuel so obtained, the quantity used and quantity on hand, and cost of the fuel classified as to the nature of the costs and expenses incurred with appropriate adjustment for the inventories at beginning and end of year.

Line No.	Item (a)	Total Cost (b)	KINDS OF FUEL AND OIL Quantity (Coal Tons) (c)	Cost (Coal) (d)
1	**On hand beginning of year**	51,129,732	1,315,437	47,725,360
2	**Received during year**	269,265,494	6,460,504	266,354,871
3	**TOTAL**	320,395,226	7,775,941	314,080,231
4	**Used during year (specify department)**			
5	Electric Generation	268,335,165	6,601,956	264,917,819
6	Storage Pile Adjustment	1,488,158	36,875	1,488,158
7				
8				
9				
10				
11				
12				
13				
14				
15	**Sold or transferred**			
16	**TOTAL DISPOSED OF**	269,823,323	6,638,831	266,405,977
17	**BALANCE END OF YEAR**	**50,571,903**	1,137,110	47,674,254

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2012

PRODUCTION FUEL AND OIL STOCKS (Included in Account 151 (Continued)

KINDS OF FUEL AND OIL (Continued)

Quantity (Oil Bbls) (e)	Cost (Oil) (f)	Quantity (g)	Cost (h)	Quantity (i)	Cost (j)	Line No.
25,418	3,404,372					1
22,294	2,910,623					2
47,712	6,314,995					3
						4
26,667	3,417,346					5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
26,667	3,417,346	0	0	0	0	16
21,045	**2,897,649**	**0**	**0**	**0**	**0**	17

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2013 No. (d)	2013 Amt. (e)
1	Balance-Beginning of Year	295,534.00	25,851,083	96,129.00	3,046,551
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	Appalachian Power Company	66,291.00	22,903,481		
10	Ohio Power Company	15,837.00	4,276,096		
11					
12					
13					
14					
15	Total	82,128.00	27,179,577		
16					
17	Relinquished During Year:				
18	Charges to Account 509	93,673.00	15,953,256		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22	AEP System Pool	4,437.00	533,123		
23					
24					
25					
26					
27					
28	Total	4,437.00	533,123		
29	Balance-End of Year	279,552.00	36,544,281	96,129.00	3,046,551
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	1,976.00		1,170.00	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	1,976.00			
40	Balance-End of Year			1,170.00	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)		788		
45	Gains		788		
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 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 acquire 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 an 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.

2014		2015		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
111,535.00	4,801,961	80,899.00		2,104,787.00		2,688,884.00	33,699,595	1
[redacted]								2
								3
				81,376.00		81,376.00		4
								5
[redacted]								6
								7
								8
						66,291.00	22,903,481	9
						15,837.00	4,276,096	10
								11
								12
								13
								14
						82,128.00	27,179,577	15
[redacted]								16
								17
	-264,320					93,673.00	15,688,936	18
[redacted]								19
								20
[redacted]								21
						4,437.00	533,123	22
								23
								24
								25
								26
								27
						4,437.00	533,123	28
111,535.00	5,066,281	80,899.00		2,186,163.00		2,754,278.00	44,657,113	29
[redacted]								30
								31
								32
								33
								34
								35
[redacted]								
357.00		357.00		56,199.00		60,059.00		36
				714.00		714.00		37
								38
				357.00		2,333.00		39
357.00		357.00		56,556.00		58,440.00		40
[redacted]								41
								42
								43
					150		938	44
					150		938	45
								46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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.

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2013 No. (d)	2013 Amt. (e)
1	Balance-Beginning of Year	24,845.00	776,665	23,740.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	2,152.00			
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	Accrued Purchase Reversal	-327.00	-88,104		
10	Buckeye Power, Inc.	216.00	229,356		
11	Element Markets, LLC	550.00	24,750		
12	NRG Power Marketing, LLC	625.00	32,813		
13	Seminole Electric Co-op	1,900.00	97,500		
14	Other	1,900.00	27,904		
15	Total	4,864.00	324,219		
16					
17	Relinquished During Year:				
18	Charges to Account 509	31,313.00	1,093,514	1,021.00	
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	548.00	7,370	22,719.00	
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				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 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 acquire 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 an 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.

2014 No. (f)	2014 Amt. (g)	2015 No. (h)	2015 Amt. (i)	Future Years No. (j)	Future Years Amt. (k)	Totals No. (l)	Totals Amt. (m)	Line No.
23,740.00						72,325.00	776,665	1
[redacted]								2
								3
						2,152.00		4
								5
[redacted]								6
								7
								8
						-327.00	-88,104	9
						216.00	229,356	10
						550.00	24,750	11
						625.00	32,813	12
						1,900.00	97,500	13
						1,900.00	27,904	14
						4,864.00	324,219	15
[redacted]								16
								17
						32,334.00	1,093,514	18
[redacted]								19
								20
[redacted]								21
								22
								23
								24
								25
								26
								27
								28
23,740.00						47,007.00	7,370	29
[redacted]								30
								31
								32
								33
								34
								35
[redacted]								
								36
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								39
								40
[redacted]								41
								42
								43
								44
								45
								46

Schedule Page: 229 Line No.: 14 Column: b

	No.	Amount
Alcoa Allowance Management, Inc.	800	11,804
Constellation Energy Commodities Group, Inc.	1,000	14,500
TC Ravenswood, LLC	100	1,600
Total	1,900	27,904

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2012

MISCELLANEOUS CURRENT AND ACCRUED ASSETS (Account 174)

1. Give description and amount of other current and accrued assets as of the end of year.
2. Minor items may be grouped by classes, showing number of items in each class.

Line No.	Item (a)	Balance End of Year (b)
1	Deferred Cook Unit 1 Fire Expenses	80,000,000
2	Department of Energy Spent Fuel Canister Reimbursement	45,172,733
3		
4		
5		
6		
7		
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11		
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14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25	TOTAL	**125,172,733**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	PJM #T126 Olive-Dequine 345 KV	99	186	99	186
3	PJM #T183 Olive-Dequine 345 KV	14,189	186	14,157	186
4	PJM #T184 Olive-Dequine 345 KV	6,677	186	6,298	186
5	PJM #U1-087 Dequine 345 KV	10,913	186	10,913	186
6	PJM #U1-088 Dequine 345 KV	6,627	186	6,627	186
7	PJM #U4-033 Olive -Dequine 345 KV	1,392	186	1,392	186
8	PJM #S71 Bluff Point 138KV	11,676	186		
9	PJM #S73 Lincoln-N. Delphos 138KV	11,549	186		
10	PJM #S72 Conroy-E. Lima 345 KV	24,111	186	19,267	186
11	PJM #T130 Robison -E. Lima 138KV	9,147	186	2,385	186
12	PJM #T131 Ft. Wayne-Lima 138KV	8,869	186	2,618	186
13	PJM #T142 E. Lima-Marysville 345KV	5,524	186		
14	PJM #U2-091Delaware-Richmond 345KV	18	186	18	186
15	PJM #U2-092 Delaware-Center 138KV	2,958	186		
16	PJM #V3-007 Desoto-Tanners 345KV			1,039	186
17	PJM #V3-008 Desoto-Tanners 345KV			1,029	186
18	PJM #V3-009 Desoto-Tanners 345KV			1,029	186
19	PJM #V4-016 Valley 138KV	31,289	186	25,021	186
20	PJM #V1-012 Haviland 138KV	3,283	186	193	186
21	**Generation Studies**				
22					
23					
24					
25					
26					
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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 Written off During the Quarter /Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	SFAS 112 Post Employment Benefits	9,137,119	996,019	228	1,236,187	8,896,951
2						
3	Cook Plant Refueling Levelization	40,550,719	37,813,862	various	51,712,920	26,651,661
4						
5	VEBA Trust Contributions	162,479		926	162,479	
6	Amort 12/2010 - 11/2012					
7	Per MPSC Case U-16180					
8						
9	SFAS 106 Post Retirement Benefits	342,147		926	342,147	
10	Amort 3/2009 - 3/2012					
11	Per IURC Cause Order #43306					
12						
13	Unamortized Loss on Reacquired Debt	2,276,487		428	206,954	2,069,533
14	Amort 1/1995 - 12/2022					
15						
16	River Transportation Selling Price Variance	1,899,173	8,508,155	254	5,831,301	4,576,027
17						
18	Unrealized Loss on Forward Commitments		66,198,631	various	65,000,166	1,198,465
19						
20	Deregulation - Customer Educ & Transition Filing	4,680,328	486,695	407,920	3,674,398	1,492,625
21						
22	Asset Retirement Obligations	3,395,767	297,632	403,411	2,885,464	807,935
23	Amortz 3/2009 - 3/2020					
24	Per IURC Cause Order #43306					
25						
26	Indiana Rate Case expenses	35,878		928	35,878	
27	Amortz 3/2009 - 3/2012					
28	Per IURC Cause Order #43306					
29						
30	Michigan Rate Case expenses	112,401		928	112,401	
31	Amort 12/2010 - 11/2012					
32	Per MPSC Case U-16180					
33						
34	Michigan Rate Case expenses		184,068	928	69,010	115,058
35	Amort 04/2012 - 03/2014					
36	Per MPSC Case U-16801					
37						
38	Deferral of Michigan portion PJM Fees	3,385,291		561,575	3,385,291	
39	Amort 12/2010 - 11/2012					
40	Per MPSC Case U-16180					
41						
42	Deferred RTO Equity Carrying Charges	(508,355)	88,116			-420,239
43	Amort 1/2005 - 12/2019					

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/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 Written off During the Quarter /Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	BridgeCo Transmission Org Funding	983,019		407	87,764	895,255
2	Amort 1/2005 - 12/2019					
3	FERC Docket No. AC04-101-000					
4						
5	PJM Integration Payments	1,302,318		407	402,847	899,471
6	Amort 1/2005 - 12/2014					
7	FERC Docket No. EL05-74-000					
8						
9	Other PJM Integration	914,938		407	81,686	833,252
10	Amort 1/2005 - 12/2019					
11	FERC Docket No. AC04-101-000					
12						
13	Carrying Charges - RTO Startup Costs	601,825		407	94,828	506,997
14	Amort 1/2005 - 12/2019					
15	FERC Docket No. AC04-101-000					
16	& FERC Docket No. EL05-74-000					
17						
18	Alliance RTO Deferred Expense	564,535		407	50,402	514,133
19	Amort 1/2005 - 12/2019					
20	FERC Docket No. AC04-101-000					
21						
22	Unrecovered Fuel Cost	8,971,340	14,449,506	various	18,611,000	4,809,846
23						
24	SFAS 158 Employer Accounting for Defined	291,392,037	220,828,197	various	291,422,824	220,797,410
25	Benefit Pension & Other Postretirement Plans					
26						
27	NSR Consent Decree Settlement Expenses	211,945		506	211,945	
28	Amort 3/2009 - 3/2012					
29	Per IURC Cause Order #43306					
30						
31	DSM Energy Optimization Program - Indiana	1,386,690	1,873,835	421	652,305	2,608,220
32	Under-recovered costs					
33						
34	Indiana Clean Coal Technology Rider	56,881				56,881
35	Carrying Charges					
36	Per IURC Cause Order #43636					
37						
38	Deferred Nuclear Decommisioning Study Costs	7,667		524	4,000	3,667
39	Amort 12/2010 - 11/2013					
40	Per MPSC Case U-16180					
41						
42						
43						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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 Written off During the Quarter /Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Enhanced post-9/11 Cook Plant Security Costs	463,898		524	97,298	366,600
2	Amort 12/2010 - 11/2015					
3	Per MPSC Case U-16180					
4						
5	Deferred Severance Costs	4,952,233		various	1,264,400	3,687,833
6	Amort 12/2010 - 11/2015					
7	Per MPSC Case U-16180					
8						
9	SFAS 109 Deferred FIT	114,845,354	59,114,320	various	35,539,732	138,419,942
10						
11	SFAS 109 Deferred SIT	107,174,558	11,675,717	283	4,122,042	114,728,233
12						
13	Carbon Capture & Storage Project FEED	230,184		506	86,319	143,865
14	Study Costs - MI Portion					
15	Amortization 4/12 - 3/14					
16	Per MPSC Case U-16801					
17						
18	Carbon Capture & Storage Project FEED	1,450,142	7,286	146,234	77,272	1,380,156
19	Study Costs					
20						
21	Under Recovery of PJM Expenses	18,360,884	1,690,508	various	6,052,909	13,998,483
22						
23	City of Fort Wayne Right to Serve Settlement	4,300,000				4,300,000
24						
25	City of Fort Wayne Settlement - Carry Charge	603,082	295,295			898,377
26						
27	City of Ft. Wayne Betterments/Generation Settlement	5,900,000				5,900,000
28						
29	Cook Turbine Replacement Deferred Depreciation - Mi		335,466			335,466
30						
31	Cook Turbine Replacement CC - Michigan		727,023	421	276,208	450,815
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44	**TOTAL :**	630,142,964	425,570,331		493,790,377	561,922,918

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 Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Property Taxes	33,926,155	52,310,763	408	50,673,873	35,563,045
2						
3	Property Taxes - Capital Leases	106,171	396,161	408	412,521	89,811
4						
5	Labor Accruals	23,294	23,322	various	34,951	11,665
6						
7	Agency Fees, Factored Accts Rec	2,431,933	27,557,189	various	27,520,183	2,468,939
8						
9	River Transport Division	-237,278	165,779,125	various	165,365,188	176,659
10						
11	Deferred Rate Case expense	452,385	358,491	various	363,264	447,612
12						
13	Unamortized Credit Line Fees	1,495,337	496,207	431	897,378	1,094,166
14	Amortized thru July 2016					
15						
16	Allowances	1,392	371,135	158,509	369,484	3,043
17						
18	Defd Non-taxable Leased Assets	78,557	956,529	146	387,504	647,582
19						
20	Estimated Barging Bills			various	509,368	-509,368
21						
22	Misc Deferrals <$100,000	817	135	580	952	
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	Misc. Work in Progress	49,516				454,472
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	38,328,279				40,447,626

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report December 31, 2012

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.	Account Subdivision (a)	Balance at Beginning of Year (b)	Changes During Year: Amounts Debited to Account 410.1 (c)	Changes During Year: Amounts Credited to Account 411.1 (d)
1	Electric			
2	Accrued ARO Expense - SFAS 143	354,592,555	24,177	62,741,272
3	Reg Liability - SFAS 143 - ARO	132,006,535	13,755,341	34,249,666
4	Capitalized Cook Costs	27,640,348	7,171,814	0
5	Capitalized Interest Expense	26,492,398	1,579,142	2,608,399
6	SFAS 158	101,987,152	27,604,047	2,895,989
7	Other (see pp. 234.1A-234.1B)	56,498,365	73,943,607	89,331,521
8	TOTAL (Account 190) (Enter total of lines 2 thru 7)	699,217,353	124,078,128	191,826,847
9	Gas			
10				
11				
12				
13				
14				
15	Other	0		
16	TOTAL Gas (Enter total of lines 10 thru15)	0	0	0
17	Other (Specify)	74,834,680	0	
18	TOTAL (Account 190) *(Enter total of lines 8, 16 & 17)*	774,052,033	**124,078,128**	**191,826,847**
19	Classification of Total:			
20	Federal Income Tax	774,628,686	124,078,128	191,826,847
21	State Income Tax	(576,653)		
22	Local Income Tax			

NOTES

In the space provided below, identify by amount and classification, significant items for which deferred taxes are being provided. Indicate insignificant amounts listed under Other.

Line 17 Other - Detail	Balance at Beginning of Year	Balance at End of Year
Non-Utility 190.2 Federal	5,442,320	5,616,483
Non-Utility 190.2 State	-576,653	-751,191
SFAS 133	8,853,395	11,284,415
SFAS 87	6,087,799	3,913,442
SFAS 109	55,027,819	56,255,622
Total	74,834,680	76,318,771

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report December 31, 2012

ACCUMULATED DEFERRED INCOME TAXES (Account 190) (Continued)

3. If more space is needed, use separate pages as required.
4. In the space provided below, identify by amount and classification, significant items for which deferred taxes are being provided. Indicate insignificant amounts listed other Other.

Changes During Year		ADJUSTMENTS					
		DEBITS		CREDITS			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Acct. No. (g)	Amount (h)	Acct. No. (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
						417,309,650	2
						152,500,860	3
						20,468,534	4
						27,521,655	5
						77,279,094	6
		236	(22,388,178)	236	(11,189,798)	60,687,899	7
0	0		(22,388,178)		(11,189,798)	755,767,692	8
							9
							10
							11
							12
							13
							14
						0	15
0	0		0		0	0	16
2,569,306	2,568,932	Various	44,844,106	Various	43,359,641	76,318,771	17
2,569,306	2,568,932		22,455,928		32,169,843	832,086,463	18
							19
2,076,086	2,250,250		22,455,928		32,169,843	832,837,654	20
493,220	318,682					(751,191)	21
							22

NOTES *(Continued)*

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2012

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.	Account Subdivision (a)	Balance at Beginning of Year (b)	Changes During Year: Amounts Debited to Account 410.1 (c)	Changes During Year: Amounts Credited to Account 411.1 (d)
1				
2	Contributions and Advances for Construction	5,708,019	569,657	1,736,716
3	Provisions for Loss Trading Credit Risk	485,640	490,957	444,998
4	Property Tax Deferrals	(1,009,010)	4,574,354	3,179,798
5	Installation Allowances Capitalized	14,917	14,917	
6	Pre 04/83 Nuclear Fuel Cost	14,430,070	812,068	1,227,575
7	Nuclear Decommissioning	(446,874)	17,173	1,900
8	IRS Settlements	(3,211,497)	1,776,786	773,108
9	Deferred Gain Sale of Rockport Unit 2	13,778,432	1,297,349	37,068
10	Amortization of Step Up ITC Rockport Unit 2	4,373,999	397,718	0
11	Accrued Vacation Pay	4,695,671	936,395	992,020
12	Accrued Severance Benefits	21,266	78,109	531,909
13	Accrued Incentive Plans	9,311,619	9,336,578	9,765,047
14	Book Provision for Uncollectible Debt	612,332	700,034	168,010
15	Mark to Market Gain/Loss	8,221,019	14,292,380	11,708,153
16	Capitalized Software Tax	16,228	9,069	17,500
17	Revenue Refunds	1,252,568	417,675	1,523,857
18	SFAS 112 Post Employment Benefits	2,334,728	432,665	126,984
19				
19	Accrued Income Tax and Interest	(208,191)	334,492	794,883
20	Accrued Pension Expense	(41,478,268)	5,607,881	4,083,490
21	SFAS 106 Post Retirement Benefits	9,589,916	1,017,891	1,132
22	Accrued SIT	(201,015)		
23	Provision for Litigation	0	8,680,000	
24	NOL-Deferred Tax Asset	0		29,984,391
25	Other Miscellaneous	28,206,796	22,149,459	22,232,982
26	Total Other	56,498,365	73,943,607	89,331,521
27				
28				
29				
30				

NOTES

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2012

ACCUMULATED DEFERRED INCOME TAXES (Account 190) (Continued)

3. If more space is needed, use separate pages as required.
4. In the space provided below, identify by amount and classification, significant items for which deferred taxes are being provided. Indicate insignificant amounts listed other Other.

Changes During Year		ADJUSTMENTS					
		DEBITS		CREDITS			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Acct. No. (g)	Amount (h)	Acct. No. (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
						6,875,078	2
						439,681	3
						(2,403,566)	4
						0	5
						14,845,577	6
						(462,147)	7
						(4,215,175)	8
						12,518,151	9
						3,976,281	10
						4,751,296	11
						475,066	12
						9,740,088	13
						80,308	14
						5,636,792	15
						24,659	16
						2,358,750	17
						2,029,047	18
						0	18
						252,200	19
						(43,002,659)	20
						8,573,157	21
						(201,015)	22
						(8,680,000)	23
						29,984,391	24
		236.00	(22,388,178)	236.00	(11,189,798)	17,091,939	25
						60,687,899	26
							27
							28
							29
							30

NOTES *(Continued)*

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2012

UNAMORTIZED LOSS AND GAIN ON REACQUIRED DEBT (Account 189, 257

1. Report under separate subheadings for Unamortized Loss and Unamortized Gain on Reacquired Debt, particulars of gain and loss on reacquisition applicable to each class and series of long-term debt, including maturity date. If gain or loss resulted from a refunding transaction, include also the maturity date of the new issue.

2. In column (c) show the principal amount of bonds or other long-term debt reacquired.

3. In column (d) show the net gain or net loss realized on each debt reacquisition as computed in accordance with General Instruction 17 of the Uniform System of Accounts.

Line No.	Designation of Long-Term Debt (a)	Date Reacquired (b)	Princ. Amt. Of Debt Reacquired (c)	Net Gain or Net Loss (d)
1	7.2% Series First Mortgage Bonds. Due 2/2024.	4/2004	30,000,000	(1,270,107)
2	No Replacement Debt Issued - Amort thru 2/1/2024			
3				
4	7.5% Series First Mortgage Bonds. Due 3/2024.	4/2004	25,000,000	(1,097,914)
5	No Replacement Debt Issued - Amort thru 3/1/2024			
6				
7	8-3/4% Series First Mortgage Bonds due 2/2017	3/1994	100,000,000	(7,562,180)
8	This debt was replaced by the following issuances:			
9	6.55% FMB due 3/2004 (Replaced by 6.875% SUN)			
10	7.50% FMB due 3/2024 (Redeemed 4/2004, no replacement			
11	debt was issued.)			
12	No Replacement Debt Issued - Amort thru 2/1/2017			
13				
14	7.35% Series First Mortgage Bonds due 10/2023	5/2003	15,000,000	(383,698)
15	This debt was replaced by the following issuances:			
16	6.375% Senior Unsecured Note due 11/2012			
17	6.00% Senior Unsecured Note due 12/2032			
18				
19	8.5% Series First Mortgage Bonds due 12/2022	5/2003	75,000,000	(2,353,464)
20	This debt was replaced by the following issuances:			
21	6.375% Senior Unsecured Note due 11/2012			
22	6.00% Senior Unsecured Note due 12/2032			
23				
24	7.0% Pollution Control Revenue Bonds	11/2003	25,000,000	(600,619)
25	Lawrenceburg, IN Series Due 4/2015			
26	Replaced by 2.625% Lawrenceburg Bonds Due 10/2019			
27	Loss being amortized over life of replacement debt			
28				
29				
30	5.9% Pollution Control Revenue Bonds, due 11/2021	11/2004	52,000,000	(1,089,232)
31	City of Lawrenceberg, Indiana. (Replaced by VAR%			
32	Lawrenceberg, IN Bonds due 11/2021.)			
33				
34	9-1/4% Pollution Control Revenue Bonds, due 8/2014	8/1995	50,000,000	(3,928,658)
35	City of Rockport, Indiana.			
36	Replaced by 6.55% Rockport Bonds due 6/2025			
37	Replaced 5/06 by VAR% Rockport Bonds Due 6/2025,			
38	with $500,000 premium paid for early redemption			
39				
40	VAR% Pollution Control Revenue Bonds, due 8/2014	8/1995	50,000,000	(785,290)
41	City of Rockport, Indiana.			
42	Replaced by VAR% Rockport Bonds due 6/2025			
43				
44	7.6% Pollution Control Revenue Bonds	11/2003	40,000,000	(338,620)
45	Rockport, IN Series Due 3/2016			
46	Replaced by 2.625% Rockport IN Bonds Due 4/2025			
47	Loss being amortized over life of replacement debt.			

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2012

UNAMORTIZED LOSS AND GAIN ON REACQUIRED DEBT (Account 189, 257) (Continued)

4. Show loss amounts in red or by enclosure in parentheses.
5. Explain any debits and credits other than amortization debited to Account 428.1, Amortization of Loss on Reacquired Debt or credited to Account 429.1, Amortization of Gain on Reacquired Debt-Credit.

Balance Beginning of Year (e)	Debits During Year (f)	Credits During Year (g)	Balance End of Year (h)	Line No.
1,018,675		84,304	934,371	1
				2
				3
1,437,413		118,143	1,319,270	4
				5
				6
				7
				8
				9
				10
				11
167,743		32,999	134,744	12
				13
				14
				15
12,790		12,790	0	16
				17
				18
				19
				20
78,449		78,449	0	21
				22
				23
				24
				25
				26
448,120		57,822	390,298	27
				28
				29
838,632		85,285	753,347	30
				31
				32
				33
1,890,713		140,922	1,749,791	34
				35
				36
				37
				38
				39
352,178		26,250	325,928	40
				41
				42
				43
745,305		56,249	689,056	44
				45
				46
				47

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2012

UNAMORTIZED LOSS AND GAIN ON REACQUIRED DEBT (Account 189, 257)

1. Report under separate subheadings for Unamortized Loss and Unamortized Gain on Reacquired Debt, particulars of gain and loss on reacquisition applicable to each class and series of long-term debt, including maturity date. If gain or loss resulted from a refunding transaction, include also the maturity date of the new issue.

2. In column (c) show the principal amount of bonds or other long-term debt reacquired.

3. In column (d) show the net gain or net loss realized on each debt reacquisition as computed in accordance with General Instruction 16 of the Uniform System of Accounts.

Line No.	Designation of Long-Term Debt (a)	Date Reacquired (b)	Princ. Amt. Of Debt Reacquired (c)	Net Gain or Net Loss (d)
1	8.0% Junior Subordinated Debentures due 3/2026	5/2003	40,000,000	(1,291,678)
2	This debt was replaced by the following issuances:			
3	6.375% Senior Unsecured Note due 11/2012			
4	6.00% Senior Unsecured Note due 12/2032			
5				
6	7.6% Junior Subordinated Debentures due 6/2038	5/2003	125,000,000	(2,911,019)
7	This debt was replaced by the following issuances:			
8	6.375% Senior Unsecured Note due 11/2012			
9	6.00% Senior Unsecured Note due 12/2032			
10				
11	9.00% Pref Stock Subject to Mandatory Redemption	4/1993	40,000,000	(896,000)
12	8.60% Pref Stock Subject to Mandatory Redemption	12/1993	40,000,000	(864,000)
13	8.68% Pref Stock Subject to Mandatory Redemption	1/1994	30,000,000	(540,000)
14	7.76% Pref Stock Subject to Mandatory Redemption	3/1994	35,000,000	(798,000)
15	6.875% Pref Stock Subject to Mandatory Redemption	1/2005	15,750,000	
16	5.90% Pref Stock Subject to Mandatory Redemption	1/2005	13,200,000	(861,392)
17	6.25% Pref Stock Subject to Mandatory Redemption	1/2005	19,250,000	
18	6.30% Pref Stock Subject to Mandatory Redemption	1/2005	13,245,000	
19	(Balance transferred from FERC Acct 210 to 189)			
20				
21	VAR % Pollution Control Revenue Bonds, due 10/2019	5/2008	25,000,000	(323,600)
22	Series F Lawrenceburg			
23	Remarketed as Series I VAR%			(134,515)
24				
25				
26	VAR % Pollution Control Revenue Bonds, due 11/2021	5/2008	52,000,000	(1,013,352)
27	Series G Lawrenceburg			
28	Remarketed as Series H VAR%			(261,800)
29				
30	Early Redemption of $150M Series D Senior Unsecured Note			
31	Orginal Maturity Date of December 31, 2032			
32	Redeemed October 15, 2010			
33				
34				
35				
36	**SUBTOTAL Unamortized Losses**			
37				
38	7.35% Series First Mortgage Bonds. Due 7/2023.	6/2001	5,000,000	38,090
39	Partially reacquired and not refunded.			
40	Gain being amortized over life of retired debt.			
41				
42	**SUBTOTAL Unamortized Gains**			
43				
44	**TOTAL**			
45				
46				
47				
48				
49				
50				

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [__] A Resubmission	(Mo, Da, Yr)	December 31, 2012

UNAMORTIZED LOSS AND GAIN ON REACQUIRED DEBT (Account 189, 257) (Continued)

4. Show loss amounts in red or by enclosure in parentheses.
5. Explain any debits and credits other than amortization debited to Account 428.1, Amortization of Loss on Reacquired Debt or credited to Account 429.1, Amortization of Gain on Reacquired Debt-Credit.

Balance Beginning of Year (e)	Debits During Year (f)	Credits During Year (g)	Balance End of Year (h)	Line No.
43,056	0	43,056	0	1
				2
				3
				4
				5
97,035	0	97,035	0	6
				7
				8
				9
				10
				11
				12
				13
340,391	0		340,391	14
				15
				16
				17
				18
				19
				20
221,284	0	28,553	192,731	21
				22
122,761		15,671	107,090	23
				24
				25
742,704	0	75,529	667,175	26
				27
243,246		24,736	218,510	28
				29
6,278,198	0	298,962	5,979,236	30
				31
				32
				33
				34
				35
15,078,693	**0**	**1,276,755**	**13,801,938**	36
				37
(20,115)	1,712	-	(18,403)	38
				39
				40
				41
(20,115)	**1,712**	**-**	**(18,403)**	42
				43
15,058,578	**1,712**	**1,276,755**	**13,783,535**	44
				45
				46
				47
				48
				49
				50

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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.

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)
1	Common Stock	2,500,000		
2	TOTAL Common Stock	2,500,000		
3				
4	Preferred Stock			
5	Par Value $100	2,250,000		
6	Par Value $25	11,200,000		
7				
8				
9	TOTAL Preferred Stock	13,450,000		
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
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21				
22				
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42				

CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (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 non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
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 purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
1,400,000	56,583,866					1
1,400,000	56,583,866					2
						3
						4
						5
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Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31,2012

CAPITAL STOCK SUBSCRIBED, CAPITAL STOCK LIABILITY FOR CONVERSION, PREMIUM ON CAPITAL STOCK AND INSTALLMENTS RECEIVED ON CAPITAL STOCK (Accounts 202 & 205, 203 & 206, 207, 212)

1. Show for each of the above accounts the amounts applying to each class and series of capital stock.
2. For Account 202, *Common Stock Subscribed,* and Account 205, *Preferred Stock Subscribed,* show the subscription price and the balance due on each class at the end of year.
3. Describe in a footnote the agreement and transactions under which a conversion liability existed under Account 203, *Common Stock Liability for Conversion,* or Account 206, *Preferred Stock Liability for Conversion*, at the end of the year.
4. For Premium on Account 207, *Capital Stock*, designate with a double asterisk any amounts representing the excess of consideration received over stated values of stocks without par value.

Line No.	Name of Account & Description of Item (a)	Number of Shares (b)	Amount (c)
1	Account 202 - *Common Stock Subscribed*		
2	None		
3			
4	Account 205 - *Preferred Stock Subscribed*		
5	None		
6			
7	Account 203 - *Common Stock Liability for Conversion*		
8	None		
9			
10	Account 206 - *Preferred Stock Liability for Conversion*		
11	None		
12			
13	Account 207 - *Capital Stock*		
14	Premium on Common Stock	1,400,000	4,234,635
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33			
34			
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38			
39			
40	TOTAL	1,400,000	4,234,635

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

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 total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. 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 give brief explanation of the origin and purpose of each donation.
(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
(c) Gain on 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 which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Donations received from stockholders (Account 208)	
2	Contributed by parent company prior to 2012	972,666,991
3		
4	Subtotal Account 208	972,666,991
5		
6	Gain on reacquired capital stock (Account 210)	
7	Balance on all series	120,555
8		
9		
10	Subtotal Account 210	120,555
11		
12	Miscellaneous paid-in capital (Account 211)	
13	Amounts recorded in connection with:	
14	Merger of Indiana Service Corporation with respondent in 1948 as	
15	subsequently adjusted on December 31, 1948	1,002,503
16		
17	Acquisition of Citizen's Heat, Light and Power Company by	
18	respondent in 1954	10,687
19		
20	Merger of Michigan Power Company with respondent in 1992.	2,861,068
21	Subtotal Account 211	3,874,258
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40	TOTAL	976,661,804

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2012

SECURITIES ISSUED OR ASSUMED AND SECURITIES REFUNDED OR RETIRED DURING THE YEAR

1. Furnish a supplemental statement giving a brief description of security financing and refinancing transactions during the year and the accounting for the securities, discounts, premiums, expenses, and related gains or losses. Identify as to Commission authorization numbers and dates.
2. Furnish particulars (details) showing fully the accounting for the total principal amount, par value, or stated value of each class and series of security issued, assumed, retired, or refunded and the accounting for premiums, discounts, expenses, and gains or losses relating to the securities. Set forth the facts of the accounting clearly with regard to redemption premiums, unamortized discounts, expenses, and gains or losses relating to securities retired or refunded, including the accounting for such amounts carried in the respondent's accounts at the date of the refunding or refinancing transactions with respect to securities previously refunded or retired.
3. Include in the identification of each class and series of security, as appropriate, the interest or dividend rate, nominal date of issuance, maturity date, aggregate principal amount, par value or stated value, and number of shares. Give also the issuance of redemption price and name of the principal underwriting firm through which the security transactions were consummated.
4. Where the accounting for amounts relating to securities refunded or retired is other than that specified in General Instruction 16 of the Uniform System of Accounts, give references to the commission authorization for the different accounting and state the accounting method.
5. For securities assumed, give the name of the company for which the liability on the securities was assumed as well as particulars (details) of the transactions whereby the respondent undertook to pay obligations of another company. If any unamortized discounts, premiums, expenses, and gains or losses were taken over onto the respondent's books, furnish details of these amounts with amounts relating to refunded securities clearly earmarked.

1. Securities refunded or retired during 2012

Series	Due Date	Principal Amount	Date Retired
Series E - 6.375% Fixed Rate	11/1/2012	100,000,000	11/1/2012

2. Securities issued during 2012

Series	Due Date	Principal Amount	Date Issued
Multiple Draw Term Loan Variable Rate	5/30/2015	110,000,000	5/30/2012

3. Securities Remarketed during 2012

Series	Due Date	Principal Amount	Date Remarketed
NONE			

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

1. Report by balance sheet account the particulars (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. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. 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.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Account 222 - Reacquired Pollution Control Revenue Bonds		
2	NONE		
3	SUBTOTAL - Account 222-Reacq PCRBs		
4			
5	Account 223 - Advances From Associated Companies		
6	SUBTOTAL - Account 223-Advances From Assoc Co		
7	Account 224 - Other Long Term Debt		
8	Spent Nuclear Fuel Disposal Costs Prior		
9	To April 7, 1983 - Basic Fee Assessment & Interest		
10			
11	Pollution Control Revenue Bonds		
12	Lawrenceburg, IN		
13	Series I - Weekly Auction Rate	25,000,000	178,919
14			103,287
15			
16	Series H - Weekly Auction Rate	52,000,000	331,889
17			172,181
18	Rockport, IN		
19	Series D - 5.25% Fixed Rate	40,000,000	1,157,720
20			
21	Series 2002 A - 4.625% Fixed Rate	50,000,000	296,785
22			325,000 D
23			382,272
24			136,351 D
25			444,593
26			74,250
27			74,250
28			74,250
29			74,250
30			74,250
31			
32			
33	TOTAL	1,678,802,388	21,840,779

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/Q4

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

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, 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) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
						3
						4
						5
						6
						7
						8
				265,249,280		9
						10
						11
						12
5/22/2008	10/1/2019	5/22/2008	10/1/2019	25,000,000	35,157	13
3/24/2011	10/1/2019	3/24/2011	3/24/2013			14
						15
5/20/2008	11/1/2021	5/20/2008	11/1/2021	52,000,000	85,531	16
3/16/2011	11/1/2021	3/16/2011	3/16/2013			17
						18
4/25/2008	4/1/2025	4/25/2008	4/1/2025	40,000,000	2,100,000	19
						20
8/1/1985	6/1/2025	8/1/1985	6/1/2025	50,000,000	2,312,500	21
						22
6/1/2002	6/1/2007	6/1/2002	6/1/2007			23
						24
6/1/2007	6/1/2025	6/1/2007	6/1/2025			25
		6/1/2008	5/31/2009			26
		6/1/2009	5/31/2010			27
		6/1/2010	5/31/2011			28
		6/1/2011	5/31/2012			29
		6/1/2012	5/31/2013			30
						31
						32
				1,837,678,888	90,701,590	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

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

1. Report by balance sheet account the particulars (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. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. 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.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Series 2009 A - 6.25% Fixed Rate	50,000,000	353,976
2	per IURC Order #43445, approved 4/9/08		
3	Bonds subj to mand tender for purchase (puttable) on 6/2/14		
4			
5	Series 2009 B - 6.25% Fixed Rate	50,000,000	353,976
6	per IURC Order #43445, approved 4/9/08		
7	Bonds subj to mand tender for purchase (puttable) on 6/2/14		
8	Brokerage Fees on Auction Rate Notes		
9			
10	Senior Unsecured Notes		
11	Series E - 6.375% Fixed Rate	100,000,000	732,025
12			119,000 D
13			
14			
15	Series F - 5.05% Fixed Rate	175,000,000	1,302,944
16			637,000 D
17			
18	Amortization of Cash Flow Hedge on 5.05% SUN		
19			
20	Series G - 5.65% Fixed Rate	125,000,000	906,746
21			176.250 D
22			
23	Amortization of Cash Flow Hedge on 5.65% SUN		
24			
25	Series H - 6.05% Fixed Rate	400,000,000	3,815,383
26			2,272,000 D
27			
28	Amortization of Cash Flow Hedges on 6.05% SUN		
29			
30	Series I - 7.00% Fixed Rate	475,000,000	3,333,197
31			3,201,500 D
32			
33	TOTAL	1,678,802,388	21,840,779

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

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, 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) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
3/26/2009	6/1/2025	4/1/2009	5/31/2014	50,000,000	3,125,000	1
						2
						3
						4
3/26/2009	6/1/2025	4/1/2009	5/31/2014	50,000,000	3,125,000	5
						6
						7
						8
						9
						10
11/22/2002	11/1/2012	11/22/2002	11/1/2012		5,312,500	11
						12
						13
						14
11/16/2004	11/15/2014	11/16/2004	11/15/2014	175,000,000	8,837,500	15
						16
						17
		11/16/2004	11/15/2014		877,840	18
						19
12/7/2005	12/1/2015	12/1/2005	11/30/2015	125,000,000	7,062,500	20
						21
						22
		12/1/2005	11/30/2015		-383,570	23
						24
11/14/2006	3/15/2037	11/14/2006	3/15/2037	400,000,000	24,200,000	25
						26
						27
		11/14/2006	2/28/2037		421,740	28
						29
1/15/2009	3/15/2019	1/1/2009	2/28/2019	475,000,000	33,250,000	30
						31
						32
				1,837,678,888	90,701,590	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

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

1. Report by balance sheet account the particulars (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. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. 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.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Fort Wayne Settlement	26,802,388	
2			
3	Multiple Draw Term Loan	110,000,000	736,535
4	Variable Rate		
5	SUBTOTAL - Acct 224 - Other Long Term Debt	1,678,802,388	21,840,779
6			
7			
8			
9			
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
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25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	1,678,802,388	21,840,779

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

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, 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) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
3/1/2010	2/28/2025	3/1/2010	2/28/2025	20,429,608		1
						2
5/30/2012	5/30/2015	6/1/2012	5/30/2015	110,000,000	339,892	3
						4
				1,837,678,888	90,701,590	5
						6
						7
						8
						9
						10
						11
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						28
						29
						30
						31
						32
				1,837,678,888	90,701,590	33

Schedule Page: 256 Line No.: 9 Column: h

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. Fuel consumed prior to April 7, 1983 has been recorded as Long-term debt

Schedule Page: 256 Line No.: 13 Column: a

The $25 million City of Lawrenceburg Series I PCRB was issued 5/22/2008 & has a maturity date of 10/1/2019. It bears a weekly floating interest rate. Issuance expenses totalling $178,919 will be amortized through the original maturity date. On March 24th, 2011, these bonds were remarketed, keeping the weekly auction rate. There were $103,287 in issuance expenses incurred in this remarketing. These expenses will be amortized for 24 months.

Schedule Page: 256 Line No.: 16 Column: a

The $52 million City of Lawrenceburg Series H PCRB was issued 5/20/2008 & has a maturity date of 11/1/2021. It bears a weekly floating interest rate. Issuance expenses totalling $331,889 will be amortized through the maturity date. On March 16, 2011, these bonds were remarketed, keeping the weekly auction rate. There were $172,181 in issuance expenses incurred in this remarketing. These expenses will be amortized for 24 months.

Schedule Page: 256 Line No.: 19 Column: a

The $40 million City of Rockport Series 2003 C PCRB was re-marketed 4/25/2008 as $40 million City of Rockport Series D PCRB, at a fixed 5.25% rate. The original 4/1/2025 maturity date remained unchanged.

Schedule Page: 256 Line No.: 21 Column: a

On June 3, 2002, the $50 million Series 1985A Pollution Control Bonds were re-marketed as $50 million Series 2002A Pollution Control Bonds due June 1, 2025, at a 4.9% fixed interest rate. This did not redeem the note itself but changed the method of interest calculation, the timing of the interest payments and the maturity date of the debt. These bonds were again re-marketed in June 2007 at a 4.625% fixed interest rate. There were $444,593 in issuance expenses incurred in this re-offering and no related discount. These, plus the Issuance expenses still remaining from the Series 1985A Pollution Control Bonds, will be amortized through the June 2025 maturity date of the new Series, since no further mandatory redemption is scheduled.
An insurance policy was issued in June 2008 that guarantees the principal if Indiana Michigan Power was to default on this note. This policy cost $74,250, covers the period of June 2008 - May 2009 and was amortized over that period. This policy has been renewed annually in June 2009, June 2010, June 2011 and June 2012 each time costing $74,250 & to be fully amortized over each policy period.

Schedule Page: 256.1 Line No.: 1 Column: a

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. Issuance expenses totaling $353,976 will be amortized through the 6/2/2014 put date.

Schedule Page: 256.1 Line No.: 1 Column: e

Subject to mandatory tender for purchase (puttable) on 6/2/2014.

Schedule Page: 256.1 Line No.: 5 Column: a

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. Issuance expenses totaling $353,976 will be amortized through the 6/2/2014 put date.

Schedule Page: 256.1 Line No.: 5 Column: e

Subject to mandatory tender for purchase (puttable) on 6/2/2014.

Schedule Page: 256.1 Line No.: 11 Column: a

Note retired on November 1, 2012

Schedule Page: 256.1 Line No.: 30 Column: a

The $475 million 7.00% fixed rate Series I Senior Unsecured Note was issued 1/15/2009 with a maturity date of 3/15/2019. Issuance expenses totalling $3,333,197 & discount expense of $3,201,500 will be amortized through February 2019.

Schedule Page: 256.2 Line No.: 1 Column: a

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.

Schedule Page: 256.2 Line No.: 3 Column: a

The $110 million multiple draw term loan was issued on May 30, 2012. The interest rate is variable and the maturity date is May 30, 2015. The intial draw took place on June 4, 2012 for $20 million with a subsequent draw on November 30, 2012 for $90M.

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Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2012

PAYABLES TO ASSOCIATED COMPANIES* (Accounts 233, 234)

1. Report particulars of notes and accounts payable to associated companies at end of year.
2. Provide separate totals for Accounts 233, Notes Payable to Associated Companies, and 234, Accounts Payable to Associated Companies, in addition to total for the combined accounts.
3. List each note separately and state the purpose for which issued. Show also in column (a) date of note, maturity and interest rate.
4. Include in column (f) the amount of any interest expense during the year on notes or accounts that were paid before the end of the year.
5. If collateral has been pledged as security to the payment of any note or account, describe such collateral.

See definition on page 226B

Line No.	Particulars (a)	Balance Beginning of Year (b)	Totals for Year Debits (c)	Totals for Year Credits (d)	Balance End of Year (e)	Interest for Year (f)
1	Account 233					
2	AEP Utility Funding LLC	0	6,062,719,300	6,062,719,300	0	0
3	SUBTOTAL	0	6,062,719,300	6,062,719,300	0	0
4	Account 234					
5	AEP Transmission Companies - Various	209,526	25,068,233	27,481,613	2,622,906	
6	AEP Holding	(10,000)	0	0	(10,000)	
7	AEP Resources	28	2,608	2,580	0	
8	AEP Generating Company	26,132,100	266,268,149	266,316,320	26,180,271	
9	AEP Memco, LLC	7,563,022	75,674,059	76,056,738	7,945,701	
10	AEP Retail Energy	(0)	3,109	3,109	(0)	
11	AEP Service Corporation	13,774,914	174,126,276	178,956,751	18,605,389	
12	AEP System Pool (AEPSC)	16,871,983	547,123,973	543,856,455	13,604,465	
13	AEP Texas Central Company	(30,700)	100,527	135,378	4,151	
14	AEP Texas North Company	(472)	93,376	97,669	3,821	
15	AEP Energy Partners	0	76	76	0	
16	AEP Coal, Inc	0	5,608	5,608	0	
17	AEP Utilities, Inc	0	73,945	73,945	0	
18	AEP Utility Funding LLC	56,633	134,294	97,131	19,470	
19	American Electric Power Co	1,942,314	507,884,428	506,920,009	977,895	
20	Appalachian Power Co	4,351,760	28,963,293	47,746,188	23,134,655	
21	Blackhawk Coal Company	58,941	521,995	509,232	46,178	
22	BSE Solutions	0	2,153	2,153	0	
23	Cardinal Operating Company	4,313	4,687,448	4,693,046	9,911	
24	Conesville Coal Prep Co	0	2,510	2,510	0	
25	Cook Coal Terminal	1,215,275	42,005,049	47,139,128	6,349,354	
26	CSW Energy, Inc	0	1,376,267	1,376,267	0	
27	Electric Transmission TX	0	152,094	152,094	0	
28	Franklin Real Estate Company	0	17,934	17,934	0	
29	Indiana Franklin Realty, Inc	(0)	179,642	179,642	(0)	
30	Kentucky Power Co	10,278	244,998	312,805	78,085	
31	Kingsport Power Co	0	437	437	0	
32	Ohio Power Co	9,537,012	57,757,648	52,980,792	4,760,156	
33	Public Service Co of OK	(638,337)	460,537	1,122,095	23,221	
34	Public Liability	0	5,229	5,229	0	
35	Southwestern Electric Power Co	104,978	6,363,278	6,575,762	317,462	
36	United Sciences Testing, Inc	0	98,000	98,366	366	
37	Wheeling Power Co	0	16,769	16,769	0	
38	SUBTOTAL	81,153,568	1,739,413,942	1,762,933,831	104,673,457	0
39						
40	TOTAL	81,153,568	7,802,133,242	7,825,653,131	104,673,457	0

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2012

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-1of 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 filed, indicating, however, intercompany amounts to be eliminated in such a consolidated return. Statenames of group members, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.

Line No.		TOTAL AMOUNT
1	Utility net operating income (page 114 line 26)	209,523,376
2	Allocations:	
3	Net Other Income and Deductions	4,990,209
4	Interest Charges	96,056,169
5	Net income for the year (page 117 line 78)	118,457,416
6	Allocation of Net income for the year (see footnote)	
7	Add: Federal income tax expenses	
8		
9	Total pre-tax income	
10		
11	Add: Taxable income not reported on books:	
12		
13		
14		
15	Add: Deductions recorded on books not deducted from return	
16		
17		
18		
19	Subtract: Income recorded on books not included in return:	
20		
21		
22		
23	Subtract: Deductions on return not charged against book income:	
24		
25		
26	Federal taxable income for the year	(32,915,197)

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A resubmission	(Mo, Da, Yr)	December 31, 2012

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES (Continued)

3. Allocate taxable income between utility and other income as required to allocate tax expense between 409.1 and 409.2
4. A substitute page, designed to meet a particular need of a company, may be used as long as data is consistent and meets the requirements of the above instructions.

Utility	Other	Line No.
209,523,376		1
		2
4,990,209		3
96,056,169		4
		5
		6
		7
		8
		9
		10
		11
		12
		13
		14
		15
		16
		17
		18
		19
		20
		21
		22
		23
		24
		25
(32,915,197)		26

Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report December 31, 2012

FOOTNOTE DATA

Page Number (a)	Line Number (b)	Column Number (c)	Comments (d)	
261A	6			In (000's)
			Net Income for the year page 117	118,457
			Federal Income Taxes	41,775
			State and Local Income Taxes	(2,398)
			PreTax Book Income	157,834
			Increase (Decrease) in Taxable Income resuliting from:	
			Allowance for Funds Used During Construction and Interest Capitalized	(6,989)
			Amortization of Deferred Book Gain - Rockport Unit 1 Sale	(3,707)
			Book Accruals and Deferrals	5,411
			Book/Tax Unit Property Adj	(21,174)
			Deferred Fuel Cost	4,161
			Emission Allowances Net	(11,362)
			Equity in Earnings Subsidiary Companies	(126)
			Excess Tax vs Book Depreciation	(131,772)
			Mark to Market	(3,205)
			Nuclear Book Deferred Cost	13,899
			Nuclear Decommissioning Costs	(113,514)
			Nuclear Fuel Adjustments	26,413
			Nuclear Fuel Disposal Costs	406
			Pollution Control	48
			Property Tax	(3,303)
			Provision for Litigation	(24,800)
			Removal Costs	(14,328)
			Relocation Costs	(2,100)
			Revenue Refunds	3,161
			SFAS 143 - ARO	113,079
			Tax Accruals/Tax Deferrals	(22,290)
			Other (Net)	(316)
			Federal Tax Net Income - Estimated Current Year Taxable Income (Separate Return Basis)	(34,574)
			Current State Income Taxes	(1,659)
			Federal Taxable Income	(32,915)
			Computation Tax*	
			Federal Income Tax on Current Year Taxable Income (Separate Return Basis) at Statutory Rate of 35%	(11,520)
			Adjustment due to System Consolidation a	(999)
			Estimated Taxes Currently Payable b	(12,519)
			Tax Provision Adjustment	43
			NOL Deferred Tax Asset	30,025
			Adjustment of Prior Years Accruals(Net)	(22,767)
			Estimated Current Year Federal Income Taxes (Net)	(5,218)

(a) Represents the allocation of estimated current year net operating tax loss of American Electric Power Company, Inc.

(b) The Company joins in the filing of a consolidated Federal income tax return with its affiliated companies in the AEP system. The allocation of the AEP System's consolidated Federal income tax to the System companies allocates the benefit of current tax losses to the System companies giving rise to them in determining their current tax expense. The tax loss of the System parent company, American Electric Power Company, Inc., is allocated to its subsidiaries with taxable income. With the exception of the loss of the parent company, the method of allocation approximates a separate return result for each company in the consolidating group.

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 2012 System Federal income taxes will not be available until the consolidated Federal income tax return is completed and filed by September 2013. 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 is filed.

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TAXES ACCRUED, PREPAID AND CHARGED 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 know, 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 (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) 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.

Line No.	Kind of Tax (See instruction 5)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year	Taxes Paid During Year	Adjust-ments
		Taxes Accrued (Account 236)	Prepaid Taxes (Include in Account 165)			
	(a)	(b)	(c)	(d)	(e)	(f)
1	FEDERAL:					
2	INCOME	-17,258,566		-6,683,843	-13,129,401	1,960,046
3	FICA - 2012	2,631,973		17,351,586	17,760,002	
4	UNEMPLOYMENT - 2012	164,793		96,374	252,820	
5	EXCISE TAX - 2011	443,403		5,328	448,731	
6	EXCISE TAX - 2012			1,490,610	1,116,385	
7	SUBTOTAL Federal	-14,018,397		12,260,055	6,448,537	1,960,046
8						
9	STATE OF INDIANA:					
10	INCOME 2011	-10,018,870		731,761	-3,883,409	
11	INCOME 2012			-1,306,050		
12	UNEMPLOYMENT IN - 2012	9,939		265,154	271,139	
13	UTIL RECEIPTS TAX - 2011			-2,343	-2,343	
14	UTIL RECEIPTS TAX - 2012			15,007,000	15,007,000	
15	UTIL RECEIPTS TAX -			-2,800,000	-2,800,000	
16	INDIANA LICENSE TAX					
17	SALES & USE TAX - 2011	871,005		-9,837	861,168	
18	SALES & USE TAX - 2012			3,998,492	3,461,655	
19						
20	PUBLI SERV COMM-2011		312,823	625,647	312,824	
21	PUBLI SERV COMM-2012			635,491	953,236	
22	REAL & PERS PROP-2007			1,366	1,366	
23	REAL & PERS PROP-2008			4,220	4,220	
24	REAL & PERS PROP-2010			-221,902	-221,902	
25	REAL & PERS PROP-2011	20,264,415		-1,738,760	18,525,655	
26	REAL & PERS PROP-2012			18,849,000	1,804	
27	PERS PROP LEASED-2011	337,700		-60,410	277,290	
28	PERS PROP LEASED-2012			294,000		
29	REAL PROP LEASED-2010			-16,253	-16,253	
30	REAL PROP LEASED-2011	220,075		-13,789	206,286	
31	REAL PROP LEASED-2012			800,810	566,332	
32	SUBTOTAL Indiana	11,684,264	312,823	35,043,597	33,526,068	
33						
34						
35						
36						
37	STATE OF KENTUCKY:					
38	REAL & PERS PROP-2011	-26,140		26,140		
39	KY INCOME 2011	-809,487		35,236	-774,251	
40	KY INCOME 2012			-9,434	302,608	
41	TOTAL	39,814,135	986,256	83,705,146	71,649,312	-12,000,760

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) 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 (i) through (l) how the taxes were distributed. Report in column (l) 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 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) 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.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
-8,852,962		-2,962,664			-3,721,179	2
2,223,557		11,774,150			5,577,436	3
8,347		52,982			43,392	4
					5,328	5
374,225		4,990			1,485,620	6
-6,246,833		8,869,458			3,390,597	7
						8
						9
-5,403,700		788,752			-56,991	10
-1,306,050		-1,179,403			-126,647	11
3,954		197,606			67,548	12
		-2,320			-23	13
		15,007,000				14
		-2,800,000				15
						16
					-9,837	17
536,837					3,998,492	18
						19
		625,647				20
	317,745	635,491				21
		1,366				22
		4,220				23
		-221,902				24
		1,582,284			-3,321,044	25
18,847,196		15,412,673			3,436,327	26
		-4,129			-56,281	27
294,000		244,998			49,002	28
					-16,253	29
					-13,789	30
234,478					800,810	31
13,206,715	317,745	30,292,283			4,751,314	32
						33
						34
						35
						36
						37
		26,140				38
		52,904			-17,668	39
-312,042		-6,346			-3,088	40
40,058,941	1,175,988	68,164,572			15,540,574	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

TAXES ACCRUED, PREPAID AND CHARGED 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 know, 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 (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) 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.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	Subtotal Kentucky	-835,627		51,942	-471,643	
2	STATE OF MICHIGAN:					
3	MI INCOME 2011	-1,944,867		-1,653,049	-3,597,916	
4	MI INCOME 2012			-47,320	3,597,916	
5	MI SBT	-6,144		-79,813	-85,957	
6	MI CITIES	-1,279				
7	UNEMPLOYMENT - 2012	50,041		451,716	496,371	
8	PUBL SERV COMM'S-2011			205,324	205,324	
9	PUBL SERV COMM'S-2012			144,533	263,019	
10	USE TAX-2011	114,209	111,303	24,875	27,781	
11	USE TAX - 2012			1,531,104	1,205,953	
12	SALES TAX - 2011		562,130		-562,130	
13	SALES TAX - 2012				600,600	
14	REAL & PERS PROP-2010	7,204,985		-62,706	7,142,279	
15	REAL & PERS PROP-2011	30,430,029		-402,029	21,828,609	
16	REAL & PERS PROP-2012			32,250,191		
17	PERS PROP LEASED-2010	11,134		-8,777	2,357	
18	PERS PROP LEASED-2011	49,891		-34,813	8,947	
19	PERS PROP LEASED-2012			40,809		
20	REAL PROP LEASED-2010	37,710		-3,980	33,730	
21	REAL PROP LEASED-2011			208,000	179,156	
22	SUBTOTAL Michigan	35,945,709	673,433	32,564,065	31,346,039	
23						
24	DE License Tax			1,000	1,000	
25	SUBTOTAL DELAWARE			1,000	1,000	
26						
27						
28						
29						
30						
31						
32						
33						
34	STATE OF WEST VIRGINIA:					
35	LICENSE TAX			25	25	
36	WEST VA INC TAX-2009	-413,012				
37	WEST VA INC TAX-2011	-722,590		-189,342	-911,932	
38	WEST VA INC TAX-2012				384,000	
39	WVA FRANCHISE - 2011	-53,485		-77,696	-131,181	
40	WVA FRANCHISE - 2012			97,986	254,100	-50
41	TOTAL	39,814,135	986,256	83,705,146	71,649,312	-12,000,760

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) 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 (i) through (l) how the taxes were distributed. Report in column (l) 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 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) 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.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
-312,042		72,698			-20,756	1
						2
		-1,479,330			-173,719	3
-3,645,236		-24,946			-22,374	4
		-85,957			6,144	5
-1,279						6
5,386		383,230			68,486	7
		205,324				8
	118,486	144,533				9
		15,783			9,092	10
464,308	139,157	114,495			1,416,609	11
						12
	600,600					13
		-62,706				14
8,199,391		29,185,900			-29,587,929	15
32,250,191					32,250,191	16
		-8,777				17
6,131		15,078			-49,891	18
40,809					40,809	19
		-3,980				20
28,844		208,000				21
37,348,545	858,243	28,606,647			3,957,418	22
						23
		1,000				24
		1,000				25
						26
						27
						28
						29
						30
						31
						32
						33
						34
		25				35
-413,012						36
		-183,394			-5,948	37
-384,000						38
		-80,106			2,410	39
-156,164		96,802			1,184	40
40,058,941	1,175,988	68,164,572			15,540,574	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

TAXES ACCRUED, PREPAID AND CHARGED 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 know, 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 (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) 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.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
		Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)			
1	REAL & PERS PROP-2010	28,756		3,415	32,171	
2	REAL & PERS PROP-2011	26,175		19,402	26,182	
3	REAL & PERS PROP-2012			45,695		
4	WV USE TAX - 2011	2,815		-398	2,417	
5	WV USE TAX - 2012			29,302	24,524	
6	WV EXCISE TAX - 2011	86,864		550	87,414	
7	WV EXCISE TAX - 2012			311,461	236,981	
8	WV EXCISE TAX - AUDIT			200,000		
9	UNEMPLOYMENT - 2012	59,261		64,265	65,072	
10	SUBTOTAL West Virginia	-985,216		504,665	69,773	-50
11						
12	STATE OF OHIO:					
13	OHIO FRANCH TAX - 2008					
14	OHIO INCOME TAX			-2,030,123	-2,030,123	
15	OHIO CAT TAX - 2011	126,000		102,464	228,464	
16	OHIO CAT TAX - 2012			479,595	371,595	
17	SUBTOTAL Ohio	126,000		-1,448,064	-1,430,064	
18	STATE OF ILLINOIS:					
19	IL INCOME TAX - 2011	-359,031		160,875	-198,156	
20	IL INCOME TAX - 2012			151,685	230,156	
21	SUBTOTAL Illinois	-359,031		312,560	32,000	
22	STATE OF LOUISIANA:					
23	LA Franchise Tax					
24	LA REAL&PERS PROP-2010	-4,504		4,504		
25	SUBTOTAL Louisiana	-4,504		4,504		
26						
27						
28						
29						
30						
31	RAILCAR PROP TAX:					
32	Misc States - 2010			1,679	1,679	
33	Misc States - 2011			22,955	32,760	
34	Misc States - 2012			134,784	7,795	
35	MO PROP TAX - 2011	30,330		32,170	63,291	
36	NE PROP TAX-2010	68,884		-61,468	7,416	
37	NE PROP TAX-2011	52,760		-49,260		
38	WY PROP TAX-2011	12,930		17,070	29,942	
39	SUBTOTAL Railcar Prop Tax	164,904		97,930	142,883	
40	STATE OF MISSOURI					
41	TOTAL	39,814,135	986,256	83,705,146	71,649,312	-12,000,760

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) 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 (i) through (l) how the taxes were distributed. Report in column (l) 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 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) 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.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
		3,415				1
19,395		3,393			16,009	2
45,695					45,695	3
					-398	4
4,778					29,302	5
					550	6
74,480					311,461	7
200,000					200,000	8
58,454		-8,826			73,091	9
-550,374		-168,691			673,356	10
						11
						12
						13
		-2,030,123				14
		102,464				15
108,000		479,595				16
108,000		-1,448,064				17
						18
		164,145			-3,270	19
-78,471		156,388			-4,703	20
-78,471		320,533			-7,973	21
						22
						23
					4,504	24
					4,504	25
						26
						27
						28
						29
						30
						31
		1,638			41	32
-9,805		12,810			10,145	33
126,989					134,784	34
-791					32,170	35
					-61,468	36
3,500					-49,260	37
58					17,070	38
119,951		14,448			83,482	39
						40
40,058,941	1,175,988	68,164,572			15,540,574	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

TAXES ACCRUED, PREPAID AND CHARGED 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 know, 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 (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) 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.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust- ments (f)
1	UNEMPLOYMENT - 2012	-56,960				
2	MO INCOME TAX - 2011					
3	MO INCOME TAX - 2012			-408		
4	MO FRANCHISE	-1,258				
5	SUBTOTAL Missouri	-58,218		-408		
6						
7	MISC RTD PROP TX-2008	1,984,604			1,984,604	
8	MISC RTD PROP TX-2011			2,729,964		
9						
10	FED INCOME TAX FIN-48 -					
11	STATE INCOME TAX FIN-48	1,449,235		1,583,221		-512,216
12						
13	MICHIGAN LICENSE TAX			100	100	
14	VARIOUS LICENSE TAX			15	15	
15						
16	VARIOUS FRANCHISE TAX					
17						
18	FIT IRS AUDIT	4,191,841				-13,441,884
19	SIT LONG TERM	528,571				-6,656
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	39,814,135	986,256	83,705,146	71,649,312	-12,000,760

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) 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 (i) through (l) how the taxes were distributed. Report in column (l) 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 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) 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.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
-56,960						1
		6			-6	2
-408		-375			-33	3
-1,258						4
-58,626		-369			-39	5
						6
						7
2,729,964					2,729,964	8
						9
						10
2,520,240		1,604,514			-21,293	11
						12
		100				13
		15				14
						15
						16
						17
-9,250,043						18
521,915						19
						20
						21
						22
						23
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						26
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						30
						31
						32
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						34
						35
						36
						37
						38
						39
						40
40,058,941	1,175,988	68,164,572			15,540,574	41

Schedule Page: 262 Line No.: 2 Column: f

($1,375,805) - Tax Credit Carryforward

($10,033) - Fuel Tax Credit

$3,345,884 - NOL Carryforward/FIN48 Reclass

Schedule Page: 262.1 Line No.: 12 Column: a

The Rockport Plant is a two unit coal fired generating facility. Unit 1 is jointly owned and Unit 2 is jointly leased 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 and leased by Respondent and AEP Generating Company.

Schedule Page: 262.1 Line No.: 13 Column: a

Consists of a prepayment for sales tax only; a collect & remit tax. Beginning in 2009, included for purpose of reporting all prepaid tax activity.

Schedule Page: 262.1 Line No.: 40 Column: f

($50) - Franchise Tax Expense Transferred from another company

Schedule Page: 262.3 Line No.: 11 Column: f

($512,216) - FIN48 State Tax Reclass

Schedule Page: 262.3 Line No.: 18 Column: f

($2,131,638) - Federal FIN48 Reclass Entries

($11,310,246) - Reclass of Accumulated DFIT - IRS Audit

Schedule Page: 262.3 Line No.: 19 Column: f

($6,656) - FIN48 State Tax Reclass

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%						
3	4%	185,931			4114	67,289	
4	7%						
5	10%	52,446,975			4114	4,435,169	
6							
7							
8	TOTAL	52,632,906				4,502,458	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
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47							
48							

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
118,642			3
			4
48,011,806			5
			6
			7
48,130,448			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
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			45
			46
			47
			48

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) X An Original (2) _ A Resubmission	/ /	2012/Q4

FOOTNOTE DATA

Schedule Page: 266 Line No.: 8 Column: i

Remaining amortization period is 25 years.

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Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2012

MISCELLANEOUS CURRENT AND ACCRUED LIABILITIES (Account 242)

1. Give description and amount of other current and accrued liabilities as of the end of year.
2. Minor items may be grouped by classes, showing number of items in each class.

Line No.	Item (a)	Balance End of Year (b)
1	Accrued Incentive Plans	29,706,861
2	Accrued Vacation, Holiday, and Other Non-Productive	19,898,045
3	Accrued Payroll	4,955,675
4	Payroll Deductions	934,663
5	Miscellaneous Employee Benefits (2 Items)	1,987,130
6	Accrued Workers Compensation	728,808
7	Accrued Lease/Rents	54,609,619
8	Accrued Revenue Refunds	7,855,381
9	Control Cash Disbursements	10,336,606
10	Accrued Civil Penalties	10,968,113
11	Spent Nuclear Fuel Disposal Costs	4,389,033
12	Miscellaneous Current & Accrued Liabilities (9 Items)	682,621
13	Environmental Accruals	2,305,086
14	Severance Accruals	1,285,339
15		
16		
17		
18		
19		
20	TOTAL	150,642,980

CUSTOMER ADVANCES FOR CONSTRUCTION (Account 252)

Line No.	List Advances by department (a)	Balance End of Year (b)
21	None	0
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39	TOTAL	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

OTHER DEFFERED 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 Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Defd Gain-Sale of Rockport Unit 2					
2	Amtz Period 12/1989-12/2022	40,524,797	507	3,706,716		36,818,081
3						
4	Pole Attachment Rentals	588,046	454	1,784,434	1,783,573	587,185
5						
6	IPP-System Upgrade Credits	2,720,838			89,510	2,810,348
7						
8	Defd Gain-Fiber Optics Agrmt					
9	In Kind Service-Amrtz thru 2025	4,971,254	411.6	150,011		4,821,243
10						
11	Deferred Revenues-Verizon					
12	Amortized thru March 2023	533,690	451	47,438		486,252
13						
14	Deferred Revenues-KDL					
15	Amortized thru Dec 2022	98,358	451	9,348		89,010
16						
17	Customer Advance Receipts	5,132,948	142	5,132,948	5,088,462	5,088,462
18						
19	Federal Mitigation Deferral (NSR)				2,052,907	2,052,907
20						
21	SEMCO Agreement - MGP Sites	2,500,000	242	1,500,000		1,000,000
22						
23	Contract Settlement reserves	2,547,316				2,547,316
24						
25	Environmental Site Remediation	2,696,346			6,664,022	9,360,368
26						
27	Minor Items	155,667	various	1,142,541	988,949	2,075
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	62,469,260		13,473,436	16,667,423	65,663,247

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities	262,768	317	16,800
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	262,768	317	16,800
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other (provide details in footnote):			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16				
17	TOTAL (Acct 281) (Total of 8, 15 and 16)	262,768	317	16,800
18	Classification of TOTAL			
19	Federal Income Tax	262,768	317	16,800
20	State Income Tax			
21	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES _ ACCELERATED AMORTIZATION PROPERTY (Account 281) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
							3
						246,285	4
							5
							6
							7
						246,285	8
							9
							10
							11
							12
							13
							14
							15
							16
						246,285	17
							18
						246,285	19
							20
							21

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

ACCUMULATED DEFFERED 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.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	807,908,544	168,778,756	56,684,016
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	807,908,544	168,778,756	56,684,016
6	Non-Utility	323,874		
7	SFAS 109/FIN 48	59,129,283		
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	867,361,701	168,778,756	56,684,016
10	Classification of TOTAL			
11	Federal Income Tax	867,361,701	168,778,756	56,684,016
12	State Income Tax			
13	Local Income Tax			

NOTES

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
						920,003,284	2
							3
							4
						920,003,284	5
21,865	3,150					342,589	6
		various	17,144,614	various	33,426,664	75,411,333	7
							8
21,865	3,150		17,144,614		33,426,664	995,757,206	9
							10
21,865	3,150		17,144,614		33,426,664	995,757,206	11
							12
							13

NOTES (Continued)

ACCUMULATED DEFFERED 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.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	SFAS 158	101,987,213	2,895,928	27,604,047
4	Reg Asset - SFAS 143 - ARO	451,069,252	42,109,826	3,289,472
5	Deferred Cook O&M Restart Cost	14,192,750	14,589,058	19,453,729
6	Nuclear Fuel	35,395,129	46,343,272	53,475,309
7	Mark To Market	14,942,810	11,153,780	12,658,783
8	Other	38,980,579	24,441,720	17,586,292
9	TOTAL Electric (Total of lines 3 thru 8)	656,567,733	141,533,584	134,067,632
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other	188,477,571		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	845,045,304	141,533,584	134,067,632
20	Classification of TOTAL			
21	Federal Income Tax	737,870,746	141,533,584	134,067,632
22	State Income Tax	107,174,558		
23	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283) (Continued)

3. Provide in the space below explanations for Page 276 and 277. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
						77,279,094	3
						489,889,606	4
						9,328,079	5
						28,263,092	6
		various	39			13,437,768	7
255,961	98,175			various	273,463	46,267,256	8
255,961	98,175		39		273,463	664,464,895	9
							10
							11
							12
							13
							14
							15
							16
							17
3,600,477	2,437,288	various	18,162,275	various	36,452,231	207,930,716	18
3,856,438	2,535,463		18,162,314		36,725,694	872,395,611	19
							20
3,856,438	2,535,463		14,040,272		25,049,977	757,667,378	21
					4,122,042	11,675,717	114,728,233	22
							23

NOTES (Continued)

Schedule Page: 276 Line No.: 18 Column: b

	Balance at Beginning of Year	Balance at End of Year
NON-UTILITY	3,207,238	4,370,427
SFAS 133	622,604	463,993
SFAS 109	184,647,729	203,096,296
Total Line 18	188,477,571	207,930,716

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Unrealized Gain on Forward Commitments	21,784,862	456	89,828,865	87,915,623	19,871,620
2						
3	Asset Retirement Oblig-Excess Provision SFAS 143	377,161,525	228	64,257,728	122,812,944	435,716,741
4						
5	SNF Trust Funds - Pre 4/83	42,602,564	various	10,931,320	11,226,697	42,897,941
6						
7	Gains on Foreign Currency Derivatives	135,707	403	11,309		124,398
8	Amortz 1/2009 - 12/2023					
9						
10	Over-Recovered Fuel - Michigan		various	1,721,566	1,721,566	
11						
12	Clean Coal Technology Rider	1,241,996	various	2,295,135	1,826,671	773,532
13	Over-Recovered Expenses					
14						
15	DSM Environmental Optimization	11,077,508	402,442,908	7,577,719	7,579,898	11,079,687
16	Over-Recovered Carrying Charges					
17						
18	SFAS 109 Deferred FIT	33,270,719	various	3,301,456	926,905	30,896,168
19						
20	Over Recovered Environmental	200,652	182,509	2,625,883	3,376,919	951,688
21	Compliance Tracker					
22						
23	OSS Margin Sharing	5,891,773	447	1,267,715	2,987,231	7,611,289
24						
25	Residual Refund - MI Interim Rate	317,902	various	318,786	884	
26						
27	Renewable Energy Surcharge				125,734	125,734
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	493,685,208		184,137,482	240,501,072	550,048,798

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Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2012

GAIN OR LOSS ON DISPOSITION OF PROPERTY (Account 421.1 and 421. 2)

1. Give a brief description of property creating the gain or loss. Include name of party acquiring the property (when acquired by another utility or associated company) and the date transaction was completed. Identify property by type: Leased, Held for Future Use, or Nonutility.
2. Individual gains or losses relating to property with an original cost of less than $100,000 may be grouped with the number of such transactions disclosed in column (a).
3. Give the date of Commission approval of journal entries in column (b), when approval is required. Where approval is required but has not been received, give explanation following the item in column (a). (See account 102, Utility Plant Purchased or Sold.)

Line No.	Description of Property (a)	Original Cost of Related Property (b)	Date Journal Entry Approved (When Required) (c)	Account 421.1 (d)	Account 421.2 (e)
1	Gain on disposition of property:				
2					
3	Sale of Utility Property				
4	Three (3) properties each with original				
5	cost less than $100,000	3,913		23,987	
6					
7					
8	Sale of Non-Utility Property				
9	Four (4) Barges to Azcon Corp	4		104,000	
10					
11	Gain on sale of Vehicle	220		1,281	
12	(Dodge Caravan)				
13					
14					
15	Sale of Other Property				
16	Former Breed Plant Land to Indiana	240,000		362,887	
17	Department of Natural Resources				
18					
19					
20					
21					
22					
23					
24					
25					
26					
27	Total Gain	244,137		492,154	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission		December 31, 2012

GAIN OR LOSS ON DISPOSITION OF PROPERTY (Account 421.1 and 421.2) (Continued)

Line No.	Description of Property (a)	Original Cost of Related Property (b)	Date Journal Entry Approved (When Required) (c)	Account 421.1 (d)	Account 421.2 (e)
28	Loss on disposition of property:				
29					
30	Nothing to report for 2012				
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43	Total Loss	0.00			0.00

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2012

PARTICULARS CONCERNING CERTAIN OTHER INCOME ACCOUNTS

1. Report in this schedule the information specified in the instructions below for the respective other income accounts. Provide a conspicuous subheading for each account and show a total for the account. Additional columns may be added for any account if deemed necessary.
2. Merchandising, Jobbing and Contract Work (Accounts 415 and 416) - Describe the general nature of merchandising, jobbing and contract activities. Show revenues by class of activity , operating expenses classified as to operation, maintenance, depreciation, rents and net income before taxes. Give the bases of any allocations of expenses between utility and merchandising, jobbing and contract work activities.
3. Nonutility Operations (Accounts 417 and 417.1) - Describe each nonutility operation and show revenues, operating expenses classified as to operation, maintenance, depreciation, rents, amortization, and net income before taxes, from the operation. Give the bases of any allocations of expenses between utility and nonutility operations. The book cost of property classified as nonutility operations should be included in Account 121.
4. Nonoperating Rental Income (Account 418) - For each major item of miscellaneous property included in Account 121, Nonutility Property, which is not used in operations for which income is included in Account 417, but which is leased or rented to others, give name of lessee, brief description of property, effective date and expiration date of lease, amount of rent revenues, operating expenses classified as to operation, maintenance, depreciation, rents, amortization, and net income, before taxes, from the rentals. If the property is leased on a basis other than that of a fixed annual rental, state the method of determining the rental. Minor items may be grouped by classes, but the number of items so grouped should be shown. Designate any lessees which are associated companies.
5. Equity in earnings of subsidiary companies (Account 418.1) - Report the utility's equity in the earnings or losses of each subsidiary company for the year.
6. Interest and Dividend Income (Account 419) - Report interest and dividend income, before taxes, identified as to the asset account or group of accounts in which are included the assets from which the interest or dividend income was derived. Income derived from investments, Accounts 123, 124 and 136 may be shown in total. Income from sinking and other funds should be identified with the related special funds. Show also expenses included in Account 419 as required by the Uniform System of Accounts.
7. Miscellaneous Nonoperating Income (Account 421) - Give the nature and source of each miscellaneous nonoperating income, and expense and the amount for the year. Minor items may be grouped by classes.

Line No.	Item (a)	Amount (b)
1	Accounts 415 & 416 - Other Income - Merchandising,	
2	Jobbing, and Contract Work	
3	- Income	0
4	- Costs and Expenes	0
5	Total Accounts 415 & 416	0
6		
7	Account 417 - Nonutility Operations	
8	Water Transportation	
9	-Revenues	118,819,972
10	-Expenses - Operation	(104,286,912)
11	-Maintenance	(2,993,798)
12	-Depreciation, Depletion, and Amortization	(833,628)
13	-Other	0
14	Total Account 417	10,705,634
15		
16	Account 418 - Nonoperating Rental Income	
17	-Rent Revenue	491,192
18	-Expense	(44,884)
19	-Other	0
20	Total Account 418	446,308
21		
22	Account 418.1 - Equity in Earnings of Subsidiary Companies	125,886
23		
24	Account 419 - Interest and Dividend Income	
25	- Communications Leases	680,748
26	- Margin Interest	1,587
27	- Dedicated Sales	22,676
28		

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2012

PARTICULARS CONCERNING CERTAIN OTHER INCOME ACCOUNTS

Line No.	Item (a)	Amount (b)
1		
2	- Other	29,788
3	- Associated Companies	867,556
4		
5	Total Account 419	1,602,355
6		
7		
8	Account 419.1 - Allowance for Funds Used During Contruction	9,723,922
9		
10	Account 421 - Miscellaneous Nonoperating Income	
11		
12	- Power Trading	1,088,646
13	- Royalties	3,181
14	- Deregulation Implementation Carrying Charge	206,677
15	MPSC Case U-12652	
16	- Turbine Replacement Carrying Charge	450,815
17	- RTO Carrying Charges	306,644
18	- Other	128,633
19	- Rents	26,765
20	- Clean Coal Technology Carrying Charge	466,793
21	- Private Fuel Storage	(4,505)
22	- Sale of Barges	148,000
23	- Michigan Lost Net Revenue	7,478
24	- Michigan Energy Optimization	3,508
25	Total Account 421	2,832,635
26		
27	Account 421.1 - Gain on Disposition of Property	492,154
28		
29	Account 421.2 - Loss on Disposition of Property	0
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46		
47		
48		
49		
50		
51		
52		
53		
54	Total Other Income	25,928,894

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31,2012

ELECTRIC OPERATING REVENUES (Account 400)

1. Report below operating revenues for each prescribed account.
2. 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.
3. If increases or decreases from previous year (columns (c), (e), and (g)), are not derived from previously reported figures explain any inconsistencies in a footnote.

Line No.	Title of Account (a)	OPERATING REVENUES Amount for Year (b)	OPERATING REVENUES Amount for Previous Year (c)
1	Sales of Electricity		
2	(440) Residential Sales	117,523,060	106,714,162
3	(442) Commercial and Industrial Sales		
4	Small (or Commercial)	74,852,074	69,016,072
5	Large (or Industrial)	61,517,393	56,230,156
6	(444) Public Street and Highway Lighting	1,426,349	1,604,622
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	(449) Other Sales		
11			
12	TOTAL Sales to Ultimate Consumers	255,318,876	233,565,012
13			
14	(447) Sales for Resale	36,882,273	37,280,639
15	TOTAL Sales of Electricity	292,201,149	270,845,651
16			
17	(Less) (449.1) Provision for Rate Refunds	0	461,786
18	TOTAL Revenue Net of Provision for Refunds	**292,201,149**	**270,383,865**
19	Other Operating Revenues		
20	(450) Forfeited Discounts	726,403	676,684
21	(451) Miscellaneous Service Revenues	738,140	210,011
22	(453) Sales of Water and Water Power		
23	(454) Rent from Electric Property	1,067,940	1,200,449
24	(455) Interdepartmental Rents		
25	(456) Other Electric Revenues	6,310,218	(1,237,529)
26			
27			
28			
29			
30	TOTAL Other Operating Revenues	8,842,701	849,615
31			
32	TOTAL Electric Operating Revenues	**301,043,850**	**271,233,480**

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31,2012

ELECTRIC OPERATING REVENUES (Account 400) (Continued)

4. 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 footnote.)
5. See Page 108, Important Changes During Year, for important new territory added and important rate increases or decreases.
6. For line 2, 4, 5, and 6, see page 304 for amounts relating to unbilled revenue by account.
7. Include unmetered sales. Provide details of such sales in a footnote.

MEGAWATT HOURS SOLD		AVERAGE NUMBER OF CUSTOMERS PER MONTH		
Amount for Year (d)	Amount for Previous Year (e)	Number for Year (f)	Number or Previous Year (g)	Line No.
				1
1,217,370	1,247,602	109,019	109,164	2
[redacted]				3
818,042	804,630	17,410	17,369	4
801,640	795,562	975	986	5
11,182	11,269	341	328	6
				7
				8
				9
				10
				11
2,848,234	2,859,063	127,745	127,847	12
				13
623,897	611,721	5	5	14
3,472,131 **	3,470,784	127,750	127,852	15
				16
				17
3,472,131	3,470,784	127,750	127,852	18

* Include $1,795,488 unbilled revenues.

** Includes 9,372 MWH relating to unbilled revenues.

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31,2012

FOOTNOTE DATA

Page Number (a)	Line Number (b)	Column Number (c)	Comments (d)
300	25	c	The amount reported on line 25 for the year 2011 includes ($7.0M) adjustment of insurance proceeds.

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Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [ ] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2012

CUSTOMER CHOICE ELECTRIC OPERATING REVENUES

1. Report below operating revenues for each prescribed account.
2. 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.
3. If increases or decreases from pervious year (columns (c), (e), and (g)), are not derived from previously reported figures explain any inconsistencies in a footnote.

Line No.	Title of Account (a)	OPERATING REVENUES: Amount for Year (b)	OPERATING REVENUES: Amount for Previous Year (c)
1	Customer Choice Sales of Electricity		
2	Residential Sales	$ 4,831	$ -
3	Commercial and Industrial Sales		
4	Small (or Commercial)	$ 932,786	$ -
5	Large (or Industrial)	$ 1,228,514	$ -
6			
7			
8			
9			
10			
11			
12	TOTAL Customer Choice Sales	$ 2,166,131	$ -
13			
14			
15	TOTAL Sales of Electricity	$ 2,166,131	$ -
16			
17			
18	TOTAL Revenue Net of Provision for Refunds	**$ 2,166,131**	**$ -**
19	Other Operating Revenues		
20			
21			
22			
23			
24			
25			
26			
27			
28			
29			
30	TOTAL Other Operating Revenues		
31			
32	TOTAL Electric Operating Revenues	**$ 2,166,131**	**$ -**

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [ ] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2012

CUSTOMER CHOICE ELECTRIC OPERATING REVENUES (Continued)

4. 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 footnote.)
5. See Page 108, Important Changes During Year, for important new territory added and important rate increases or decreases.
6. For line 2, 4, 5, and 6, see page 304 for amounts relating to unbilled revenue by account.
7. Include unmetered sales. Provide details of such sales in a footnote.

MEGAWATT HOURS SOLD		AVERAGE NUMBER OF CUSTOMERS PER MONTH		
Amount for Year (d)	Amount for Previous Year (e)	Number for Year (f)	Number or Previous Year (g)	Line No.
				1
101	0	12	0	2
[redacted]				3
24,097	0	43	0	4
25,573	0	14	0	5
				6
				7
				8
				9
				10
				11
49,771	0	69	0	12
				13
				14
49,771	0	69	0	15
				16
				17
49,771	0	69	0	18

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31,2012

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, avg number of customers, average KWh per customer, and average revenue per KWh, excluding data for Sales for Resale, which is reported on pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," page 301. 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)	Avg. No. of Customers (d)	KWh of Sales per Customer (e)	Revenue per KWh Sold (f)
1	440 Residential Sales					
2	RESIDENTIAL SERVICE	1,107,506	105,492,936	101,868	10,872	0.0953
3	RESIDENTIAL SERVICE TOD	80,568	7,036,140	4,755	16,944	0.0873
4	RESIDENTIAL OFF PEAK ENERGY	13,599	1,013,682	581	23,406	0.0745
5	RESIDENTIAL SVC OPT SENIOR	10,849	867,396	1,815	5,977	0.0800
6	OUTDOOR LIGHTING	3,970	801,753			0.2020
7	UNBILLED	878	995,495			1.1338
8	UNRECOVERED FUEL		1,315,658			
9	Total Residential Sales	1,217,370	117,523,060	109,019	11,167	0.0965
10						
11	442 Commercial Sales					
12	SMALL GENERAL SERVICE	81,806	9,415,649	12,742	6,420	0.1151
13	MEDIUM GENERAL SERVICE	337,039	32,468,962	3,376	99,834	0.0963
14	MEDIUM GENERAL SERVICE TOD	7,330	609,259	128	57,266	0.0831
15	LARGE GENERAL SERVICE	203,656	16,449,146	211	965,194	0.0808
16	LARGE POWER	106,717	7,116,498	4	26,679,250	0.0667
17	ELECTRIC HEATING GENERAL	3,848	339,956	59	65,220	0.0883
18	ELECTRIC HEATING SCHOOLS	6,553	520,323	18	364,056	0.0794
19	MUNICIPAL & SCHOOL SERVICE	27,680	2,618,664	198	139,798	0.0946
20	IRRIGATION SERVICE	12,861	1,162,209	420	30,621	0.0904
21	WATER & SEWAGE SERVICE	25,447	1,961,703	253	100,581	0.0771
22	STREETLIGHTING SERVICE	15	1,626	1	15,000	0.1084
23	RESIDENTIAL SERVICE	0	0	0	0	0.0000
24	OUTDOOR LIGHTING	6,170	1,054,371			0.1709
25	UNBILLED	(1,080)	179,736			(0.1664)
26	UNRECOVERED FUEL		953,972			
27	Total Commercial Sales	818,042	74,852,074	17,410	46,987	0.0915
28						
29	442 Industrial Sales					
30	SMALL GENERAL SERVICE	2,903	327,351	393	7,387	0.1128
31	MEDIUM GENERAL SERVICE	147,441	13,648,351	491	300,287	0.0926
32	MEDIUM GENERAL SERVICE TOD	58	5,267	1	58,000	0.0908
33	LARGE GENERAL SERVICE	166,493	13,430,112	64	2,601,453	0.0807
34	LARGE POWER	473,813	32,204,814	22	21,536,955	0.0680
35	ELECTRIC HEATING GENERAL	463	41,425	4	115,750	0.0895
36	OUTDOOR LIGHTING	891	139,141			0.1562
37	UNBILLED	9,578	620,498			0.0648
38	UNRECOVERED FUEL		1,100,434			
39	Total Industrial Sales	801,640	61,517,393	975	822,195	0.0767

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report December 31,2012

SALES OF ELECTRICITY BY RATE SCHEDULES

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Avg. No. of Customers (d)	KWh of Sales per Customer (e)	Revenue per KWh Sold (f)
1	444 Public Street & Highway Light					
2	SMALL GENERAL SERVICE	582	78,354	162	3,593	0.1346
3	MEDIUM GENERAL SERVICE	105	10,179	2	52,500	0.0969
4	SL CUST OWNED SYS	523	48,171	7	74,714	0.0921
5	SL CUST OWNED SYS METERED	533	33,835	27	19,741	0.0635
6	MUNICIPAL & SCHOOL	150	16,614	7	21,429	0.1108
7	ENERGY CONSERV LIGHTING	4,998	669,309	87	57,448	0.1339
8	STREETLIGHTING SERVICE	4,195	540,901	49	85,612	0.1289
9	OUTDOOR LIGHTING	101	17,311			0.1714
10	UNBILLED	(5)	(240)			0.0480
11	UNRECOVERED FUEL		11,915			
12	Total Public Street & Highway Light	11,182	1,426,349	341	32,792	0.1276
13						
14	Fuel Clause (see footnote)					
15						
16						
17						
18						
19						
20						
21						
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44						
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47						
48						
49						
50						
51						
52						
53						
54						
55	Total Billed	2,838,862	253,523,388	127,745	22,223	0.0893
56	Total Unbilled Rev. (See Instr. 6)	9,372	1,795,488			0.1916
57	TOTAL	**2,848,234**	**255,318,876**	**127,745**	22,296	0.0896

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31,2012

FOOTNOTE DATA

Page Number (a)	Line Number (b)	Column Number (c)	Comments (d)	
304.1	14	a	440 Residential Sales	
			RESIDENTIAL SERVICE	(1,004,371)
			RESIDENTIAL SERVICE TOD	(70,089)
			OUTDOOR LIGHTING	(3,398)
			RESIDENTIAL OFF PEAK ENERGY STORAGE	(10,722)
			RESIDENTIAL SVC OPT SENIOR CITIZEN	(10,220)
			RESIDENTIAL TOTAL	(1,098,800)
			442 Commercial Sales	
			SMALL GENERAL SERVICE	(72,295)
			MEDIUM GENERAL SERVICE	(306,652)
			MEDIUM GENERAL SERVICE TOD	(7,062)
			LARGE GENERAL SERVICE	(159,230)
			LARGE POWER	(74,435)
			ELECTRIC HEATING GENERAL	(3,392)
			ELECTRIC HEATING SCHOOLS	(4,589)
			MUNICIPAL & SCHOOL SERVICE	(22,575)
			IRRIGATION SERVICE	(18,743)
			WATER & SEWAGE SERVICE	(21,738)
			OUTDOOR AND STREET LIGHTING	(5,278)
			COMMERCIAL TOTAL	(695,989)
			442 Industrial Sales	
			SMALL GENERAL SERVICE	(2,434)
			MEDIUM GENERAL SERVICE	(130,849)
			MEDIUM GENERAL SERVICE TOD	(57)
			LARGE GENERAL SERVICE	(124,184)
			LARGE POWER	(363,887)
			ELECTRIC HEATING GENERAL	(361)
			OUTDOOR AND STREET LIGHTING	(757)
			INDUSTRIAL TOTAL	(622,529)
			444 Public Street & Highway Light	
			SMALL GENERAL SERVICE	(742)
			MEDIUM GENERAL SERVICE	(88)
			SL CUST OWNED SYS	(417)
			SL CUST OWNED SYS METERED	(448)
			MUNICIPAL & SCHOOL SERVICE	(120)
			OUTDOOR AND STREET LIGHTING	(3,422)
			ENERGY CONSERVE LIGHTING	(4,004)
			PUBLIC STREET & HIGHWAY LIGHT TOTAL	(9,241)
			GRAND TOTAL	**(2,426,559)**

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [ ] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2012

CUSTOMER CHOICE SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, avg number of customers, average KWh per customer, and average revenue per KWh, excluding data for Sales for Resale, which is reported on pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," page 301. 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)	Avg. No. of Customers (d)	KWh of Sales per Customer (e)	Revenue per KWh Sold (f)
1	440 Residential Sales					
2	Residential Service	93	$ 4,262	12	7,750	$ 0.04583
3	Unbilled	8	$ 569			$ 0.07113
4	Total Residential Sales	101	$ 4,831			$ 0.04783
5						
6						
7	442 Commercial Sales					
8	Electric Heating General	5	$ 341		0	$ 0.06820
9	Electric Heating Schools	223	$ 17,155	2	111,500	$ 0.07693
10	Small General Service	170	$ 8,431	22	7,727	$ 0.04959
11	Medium General Service	921	$ 51,073	12	76,750	$ 0.05545
12	Large General Service	5,990	$ 262,329	5	1,198,000	$ 0.04379
13	Large Power	14,020	$ 461,413		0	$ 0.03291
14	Municipal and School Service	227	$ 14,456	2	113,500	$ 0.06368
15	Misc	24	$ 2,590		0	$ 0.10792
16	Unbilled	2,517	$ 114,998			$ 0.04569
17	Total Commercial Sales	24,097	$ 932,786			$ 0.03871
18						
19						
20	442 Industrial Sales					
21	Small General Service	13	$ 765	2	6,500	$ 0.05885
22	Medium General Service	4,182	$ 235,610	8	522,750	$ 0.05634
23	Large General Service	5,714	$ 283,036	2	2,857,000	$ 0.04953
24	Large Power	12,292	$ 533,258	2	6,146,000	$ 0.04338
25	Unbilled	3,372	$ 175,845			$ 0.05215
26	Total Commercial Sales	25,573	$ 1,228,514			$ 0.04804
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42	Total Billed	43,874	$ 1,874,719	69	635,855	$ 0.04273
43	Total Unbilled Rev. (See Instr. 6)	5,897	$ 291,412			$ 0.04942
44	TOTAL	49,771	$ 2,166,131	69	721,319	$ 0.04352

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 326-327).
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.

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) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	City of Auburn	RQ	Note 2			
2	City of Bluffton	RQ	IMPCO#104			
3	City of Dowagiac, MI	RQ	Note1			
4	City of Garrett	RQ	IMPCO#109			
5	City of Mishawaka	RQ	IMPCO#102			
6	City of Niles	RQ	IMPCO#106			
7	City of South Haven	RQ	IMPCO#108			
8	City of Sturgis	RQ	IMPCO#107			
9	Indiana Municipal Power Agency	RQ	IMPCO#101			
10	Town of Avila	RQ	IMPCO#105			
11	Town of New Carlisle	RQ	IMPCO#103			
12	Town of Warren	RQ	IMPCO#110			
13	Village of Paw Paw	RQ	IMPCO#111			
14	Wabash Valley Power Assoc Inc.	RQ	IMPCO#112			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

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 (9) 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.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
460,874	1,755,897	24,032,583		25,788,480	1
311,893	10,874,039	6,358,776		17,232,815	2
69,694	2,718,100	1,432,529		4,150,629	3
93,859	3,721,520	1,933,229		5,654,749	4
624,570	24,769,816	13,711,527		38,481,343	5
136,569	4,881,382	2,982,294		7,863,676	6
144,766	5,250,623	3,172,911		8,423,534	7
228,621	8,910,762	4,962,012		13,872,774	8
1,643,766	50,496,962	30,449,715		80,946,677	9
35,273	1,376,911	746,110		2,123,021	10
12,227	499,908	322,493		822,401	11
19,101	773,849	438,441		1,212,290	12
44,247	1,802,933	1,112,670		2,915,603	13
1,211,469	46,973,472	25,985,852		72,959,324	14
5,036,929	164,806,174	117,641,142	-27,923,624	254,523,692	
17,958,337	8,294,886	469,864,565	0	478,159,451	
22,995,266	**173,101,060**	**587,505,707**	**-27,923,624**	**732,683,143**	

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 326-327).
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.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	PJM Transmission for RQ Customers	RQ	Various			
2	AEP Service Corporation	OS	17			
3	AEP Service Corporation	OS	20			
4	AEP Service Corporation	OS				
5	Advan Promotions Inc.	OS	Note1			
6	Allegheny Electric Cooperative	OS	Note1			
7	Ameren CILCO	OS	Note1			
8	Ameren Energy Marketing	OS	Note1			
9	American Municipal Power-Ohio	OS	Note1			
10	American PowerNet Management	OS	Note1			
11	Associated Elect Cooperative	OS	Note1			
12	B.P. Energy Company	OS	Note1			
13	Barclays Bank PLC	OS	Note1			
14	Beech Ridge Energy LLC	OS	Note1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

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 (9) 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.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
			-27,923,624	-27,923,624	1
8,563		218,622		218,622	2
		32,828		32,828	3
12,438,038	1,931,817	263,990,654		265,922,471	4
		-7,338		-7,338	5
101,784		5,535,704		5,535,704	6
3,423		141,937		141,937	7
-28,883		-1,193,274		-1,193,274	8
73,689	909,188	4,342,598		5,251,786	9
16,562		689,896		689,896	10
-1,701		-45,667		-45,667	11
16,723		931,582		931,582	12
57,152		2,260,106		2,260,106	13
		-51,035		-51,035	14
5,036,929	164,806,174	117,641,142	-27,923,624	254,523,692	
17,958,337	8,294,886	469,864,565	0	478,159,451	
22,995,266	**173,101,060**	**587,505,707**	**-27,923,624**	**732,683,143**	

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) / /	End of 2012/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 326-327).
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.

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) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	BP AMOCO	OS	Note1			
2	Buckeye Rural Electric Admin	OS	Note1			
3	California Power Exchange	OS	Note1			
4	Calpine Power Service Company	OS	Note1			
5	Carolina Power & Light	OS	IMPCO#77			
6	Citigroup Energy Inc.	OS	Note1			
7	Citizens Elect Co & Wellsborough	OS	Note1			
8	City of Batavia	OS	Note1			
9	City of Columbus	OS	Note1			
10	City of Croswell, MI	OS	Note1			
11	City of Dowagiac, MI	OS	Note 1			
12	City of Medford	OS	Note1			
13	City of Shelby	OS	Note1			
14	City of Westerville	OS	Note1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

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 (9) 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.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
		138,542		138,542	1
50,286		22,408,552		22,408,552	2
		905		905	3
-962		-22,423		-22,423	4
216		7,152		7,152	5
		55,383		55,383	6
2,085		109,868		109,868	7
5,414		203,307		203,307	8
181,304		12,005,176		12,005,176	9
8,587		416,200		416,200	10
		990		990	11
26,480		1,535,938		1,535,938	12
7,410		529,187		529,187	13
57,665		4,832,841		4,832,841	14
5,036,929	164,806,174	117,641,142	-27,923,624	254,523,692	
17,958,337	8,294,886	469,864,565	0	478,159,451	
22,995,266	**173,101,060**	**587,505,707**	**-27,923,624**	**732,683,143**	

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 326-327).
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.

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) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	City of Kirkwood, Missouri	OS	Note1			
2	Cleveland Public Power	OS	Note1			
3	Cleveland Toledo OH PA Electric	OS	Note1			
4	Commonwealth Edison Company	OS	Note1			
5	Conoco Inc.	OS	Note1			
6	Constellation Energy Commodities	OS	Note1			
7	Cook Inlet Energy Supply LP	OS	Note1			
8	Dairyland Power Cooperative	OS	Note1			
9	DB Energy Trading LLC	OS	Note1			
10	Delaware Electric Municipal Co	OS	Note1			
11	Dominion Equipment Inc.	OS	Note1			
12	DP&L Power Services	OS	Note1			
13	DTE Energy Trading Inc.	OS	Note1			
14	Duke Energy Carolinas, LLC	OS	Note1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

SALES FOR RESALE (Account 447) (Continued)

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 (9) 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.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
	102			102	1
41,154		2,148,209		2,148,209	2
	331,632	-414		331,218	3
76,704		3,257,343		3,257,343	4
		193,529		193,529	5
-1,862		-707,505		-707,505	6
		111,342		111,342	7
1,602		52,957		52,957	8
100,701		3,733,889		3,733,889	9
37,640		2,446,589		2,446,589	10
6,844		271,009		271,009	11
		-240,357		-240,357	12
	4,706	-11,618		-6,912	13
62		-1,292		-1,292	14
5,036,929	164,806,174	117,641,142	-27,923,624	254,523,692	
17,958,337	8,294,886	469,864,565	0	478,159,451	
22,995,266	**173,101,060**	**587,505,707**	**-27,923,624**	**732,683,143**	

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 326-327).
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.

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) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Duke Energy Indiana, Inc.	OS	Note1			
2	Duke Energy Ohio, Inc.	OS	Note1			
3	Easton Utilities	OS	Note1			
4	East KY Power Co-Op Power Mktg	OS	Note1			
5	EDF Trading North America LLC	OS	Note1			
6	Edison Mission Mktg & Trading	OS	Note1			
7	Endure Energy, LLC	OS	Note1			
8	Energy America, LLC	OS	Note1			
9	Eng Mktg, div of Amerada Hess	OS	Note1			
10	Entergy Power Serv	OS	Note1			
11	Exelon Generation - Power Team	OS	Note1			
12	FirstEnergy Trading Services	OS	Note1			
13	GBC Metals, LLC	OS	Note1			
14	Great River Energy	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

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 (9) 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,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE: Demand Charges ($) (h)	REVENUE: Energy Charges ($) (i)	REVENUE: Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
		388,110		388,110	1
75,240		3,746,254		3,746,254	2
10,938		593,529		593,529	3
91,147		3,500,106		3,500,106	4
148,122		7,344,159		7,344,159	5
	142,659	24,565		167,224	6
		-2,475		-2,475	7
		830,339		830,339	8
		1,107,431		1,107,431	9
-624		-27,090		-27,090	10
-10,702		-10,346,120		-10,346,120	11
468,623		26,925,153		26,925,153	12
		20,512		20,512	13
		-34,494		-34,494	14
5,036,929	164,806,174	117,641,142	-27,923,624	254,523,692	
17,958,337	8,294,886	469,864,565	0	478,159,451	
22,995,266	**173,101,060**	**587,505,707**	**-27,923,624**	**732,683,143**	

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 326-327).
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.

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) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Harrison Rural Electrification	OS	Note1			
2	Hoosier Power Market	OS	Note1			
3	Illinois Municipal Elec Agency	OS	Note1			
4	Illinois Power Authority	OS	Note 1			
5	Indiana Municipal Power Agency	OS	Note1			
6	Indianapolis Power & Light Co	OS	Note1			
7	Interstate Gas Supply, Inc.	OS	Note 1			
8	Integrys Energy Services, Inc	OS	Note1			
9	Interstate Power & Light Co	OS	Note1			
10	J Aron & Company	OS	Note1			
11	JP Morgan Ventures Energy Corp	OS	Note1			
12	Kansas City Power & Light Co	OS	Note1			
13	Kentucky Municipal Power Agency	OS	Note1			
14	Letterkenny Industrial Dev Auth	OS	Note1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

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 (9) 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.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
19,752		1,585,031		1,585,031	1
4,494		118,299		118,299	2
99		7,015		7,015	3
		-102		-102	4
	4,998	44,648		49,646	5
	10,061			10,061	6
		-2,544		-2,544	7
		169,084		169,084	8
15,851		352,682		352,682	9
583,975		16,807,309		16,807,309	10
106,567		-1,330,593		-1,330,593	11
-135		-3,281		-3,281	12
14,249		823,421		823,421	13
15,694		1,049,112		1,049,112	14
5,036,929	164,806,174	117,641,142	-27,923,624	254,523,692	
17,958,337	8,294,886	469,864,565	0	478,159,451	
22,995,266	**173,101,060**	**587,505,707**	**-27,923,624**	**732,683,143**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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 326-327).
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.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	LG&E Utilities Power Sales	OS	Note1			
2	L&P Electric, Inc.	OS	Note1			
3	Michigan Public Power Agency	OS	Note1			
4	MidAmerican Energy	OS	Note1			
5	Midwest ISO	OS	Note1			
6	Minnesota Power	OS	Note 1			
7	Mizuho Securities USA Inc	OS	Note1			
8	Morgan Stanley Capt.	OS	Note1			
9	NC Electric Membership Corp.	OS	Note1			
10	NextEra Energy Power Mktg LLC	OS	Note1			
11	North Carolina Muni Power Agency	OS	Note1			
12	Noble Americas Gas and Power Corp	OS	Note1			
13	NRG Power Marketing Inc.	OS	Note1			
14	NSP Energy Marketing	OS	Note1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

SALES FOR RESALE (Account 447) (Continued)

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 (9) 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.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
94		2,925		2,925	1
6,534		234,468		234,468	2
26,091		1,582,009		1,582,009	3
		-725,043		-725,043	4
-591,092		-18,473,067		-18,473,067	5
-6,100		-149,659		-149,659	6
		2,270,839		2,270,839	7
6,016		-255,728		-255,728	8
452,134		17,059,423		17,059,423	9
2,073		759,168		759,168	10
33		1,008		1,008	11
		58,508		58,508	12
-26,698		-737,163		-737,163	13
		182,006		182,006	14
5,036,929	164,806,174	117,641,142	-27,923,624	254,523,692	
17,958,337	8,294,886	469,864,565	0	478,159,451	
22,995,266	**173,101,060**	**587,505,707**	**-27,923,624**	**732,683,143**	

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 326-327).
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.

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) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Old Dominion Electric	OS	Note1			
2	OSS Over/Under	OS	Note1			
3	Otter Tail Power Company	OS	Note1			
4	OVEC Power Scheduling	OS	Note 1			
5	Paribas	OS	Note1			
6	PECO Energy	OS	Note1			
7	PEPCO Services Inc.	OS	Note1			
8	PJM Environmental Info System Inc.	OS	Note1			
9	PJM Interconnection	OS	Note1			
10	Potomac Electric Power Company	OS	Note1			
11	PPL Energy Plus	OS	Note 1			
12	PPL Electric Utilities Corp	OS	Note1			
13	Prairie Power, Inc.	OS	Note1			
14	Prairieland Energy Incorporate	OS	Note1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

SALES FOR RESALE (Account 447) (Continued)

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 (9) 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.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
67,749		3,311,395		3,311,395	1
		-1,719,516		-1,719,516	2
		5,272		5,272	3
21,342		756,703		756,703	4
		4,687		4,687	5
6,628		481,517		481,517	6
11,292		595,650		595,650	7
		-140		-140	8
2,440,357	4,957,551	61,730,530		66,688,081	9
61,481		4,713,017		4,713,017	10
		-1,792,413		-1,792,413	11
14,092		980,112		980,112	12
20,323		1,338,276		1,338,276	13
38,078	-35	1,236,459		1,236,424	14
5,036,929	164,806,174	117,641,142	-27,923,624	254,523,692	
17,958,337	8,294,886	469,864,565	0	478,159,451	
22,995,266	**173,101,060**	**587,505,707**	**-27,923,624**	**732,683,143**	

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 326-327).
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.

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) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	PSEG Energy Resources & Trade	OS	Note1			
2	Quasar Energy Power Marketing	OS	Note1			
3	Sempra Energy Solutions, LLC	OS	Note1			
4	Shell Energy N America (US) LP	OS	Note1			
5	Southen Maryland Elec Coop Inc	OS	Note1			
6	Southern Company	OS	Note1			
7	Southern Illinois Power Co-Op	OS	Note1			
8	Tenaska Power Services Company	OS	Note1			
9	The Borough of Pitcairn, PA	OS	Note1			
10	The Energy Authority	OS	Note1			
11	The Potomac Edison Company	OS	Note1			
12	Timber Canyon	OS	Note1			
13	Town of Berlin, Maryland	OS	Note1			
14	Town of Hagerstown, Indiana	OS	Note1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

SALES FOR RESALE (Account 447) (Continued)

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 (9) 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.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
29,981		900,587		900,587	1
-658		-17,366		-17,366	2
		1,589,117		1,589,117	3
32		1,643		1,643	4
1,068		60,323		60,323	5
3,507		103,320		103,320	6
3,410		112,779		112,779	7
-81		-1,695		-1,695	8
2,683		115,247		115,247	9
3,221		117,568		117,568	10
317		18,648		18,648	11
		-7,338		-7,338	12
8,752		554,089		554,089	13
4,983		304,193		304,193	14
5,036,929	164,806,174	117,641,142	-27,923,624	254,523,692	
17,958,337	8,294,886	469,864,565	0	478,159,451	
22,995,266	**173,101,060**	**587,505,707**	**-27,923,624**	**732,683,143**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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 326-327).
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.

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) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	TVA Bulk Power Trading	OS	Note1			
2	UBS Securities LLC	OS	Note1			
3	UBS AG, London Branch	OS	Note 1			
4	Union Electric Company	OS	Note1			
5	Union Power Partners	OS	Note1			
6	Village of Bethel, Ohio	OS	Note1			
7	Village of Glouster	OS	Note1			
8	Village of Hammersville, Ohio	OS	Note1			
9	Village of Ripley, Ohio	OS	Note1			
10	Village of Sebewaing, MI	OS	Note1			
11	Virginia City Hybrid Energy Center	OS	Note1			
12	Wabash Valley Power Assn Inc.	OS	Note1			
13	Washington Gas Energy Services	OS	Note1			
14	West Penn Power Company	OS	Note1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

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 (9) 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, iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
305		20,310		20,310	1
		-11,737,054		-11,737,054	2
		-171,961		-171,961	3
		-452,670		-452,670	4
-1,555		-32,489		-32,489	5
5,802		300,758		300,758	6
346		70,054		70,054	7
1,077		59,460		59,460	8
3,955		203,617		203,617	9
9,425		451,248		451,248	10
		221,273		221,273	11
		165,235		165,235	12
220,647		10,855,657		10,855,657	13
-81		-4,297		-4,297	14
5,036,929	164,806,174	117,641,142	-27,923,624	254,523,692	
17,958,337	8,294,886	469,864,565	0	478,159,451	
22,995,266	**173,101,060**	**587,505,707**	**-27,923,624**	**732,683,143**	

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 326-327).
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.

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) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Westar Energy Inc.	OS	Note1			
2	Wisconsin Power & Light	OS	Note1			
3	Wolverine Power Supply Coop	OS	Note1			
4	Adjustments					
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

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 (9) 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.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
20,216		378,033		378,033	1
14,596		531,033		531,033	2
245,992	2,207	8,575,783		8,577,990	3
		-883,755		-883,755	4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
5,036,929	164,806,174	117,641,142	-27,923,624	254,523,692	
17,958,337	8,294,886	469,864,565	0	478,159,451	
22,995,266	**173,101,060**	**587,505,707**	**-27,923,624**	**732,683,143**	

Schedule Page: 310 Line No.: 1 Column: c

NOTE 2 - I&M FERC Electric Tariff, Original Vol. No. 7, SA No. 013

Schedule Page: 310 Line No.: 1 Column: k

Margins for Off System Sales (OSS) reported in I&M's generation formula rates are included in the total revenue amount. The margins are specifically identified in the ledger as a subset of the accounts that make up these OSS revenues.

Schedule Page: 310 Line No.: 3 Column: c

NOTE 1: FERC Electric Tariff, Second Substitute Volume No. 5 (1st quarter 2009)
FERC Electric Tariff, First Revised Volume No. 5 (2nd, 3rd, and 4th quarter 2009)

Schedule Page: 310.1 Line No.: 1 Column: j

Amount represents transmission services and related charges.

Schedule Page: 310.1 Line No.: 2 Column: a

Affiliated Company transactions related to the System Integration Agreement. See pages 122-123 (Notes to Financial Statements) Related Party Transactions - System Integration Agreement for additional information.

Schedule Page: 310.1 Line No.: 3 Column: a

Affiliated Company transactions related to the System Integration Agreement. See pages 122-123 (Notes to Financial Statements) Related Party Transactions - System Integration Agreement for additional information.

Schedule Page: 310.1 Line No.: 4 Column: a

Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company and Ohio Power Company are associated companies and members of the American Electric Power System Power Pool, whose electric facilities are interconnected at a number of points and are operated in a fully coordinated manner on a system pool basis. Power transactions between the members of the AEP System Pool are governed by the terms of the interconnection agreement dated July 6, 1951, as amended, and are processed by American Electric Power Service Corporation.

Schedule Page: 310.7 Line No.: 4 Column: a

An affiliated company.

Schedule Page: 310.10 Line No.: 4 Column: a

Reclass between 447 and 555 accounts to incorporate certain trading/marketing activity. The amounts represented on Page 310-11 and 326-27 are equal and off-setting.

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Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2012

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amt. For Current Year (b)	Amt. For Previous Year (c)
1	**1. POWER PRODUCTION EXPENSES**		
2	**A. Steam Power Generation**		
3	Operation		
4	(500) Operation Supervision and Engineering	6,068,133	6,765,439
5	(501) Fuel	286,390,555	298,113,614
6	(502) Steam Expenses	9,585,347	6,830,702
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred - **CR.**		
9	(505) Electric Expenses	1,571,953	1,673,806
10	(506) Miscellaneous Steam Power Expenses	16,909,050	(10,165,847)
11	(507) Rents	70,141,543	70,144,622
12	(509) Allowances	17,533,485	20,635,992
13	TOTAL Operation *(Enter Total of Lines 4 thru 12)*	408,200,066	393,998,328
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	3,738,924	3,832,343
16	(511) Maintenance of Structures	2,120,896	3,009,253
17	(512) Maintenance of Boiler Plant	15,794,382	23,347,481
18	(513) Maintenance of Electric Plant	3,851,616	8,023,365
19	(514) Maintenance of Miscellaneous Steam Plant	1,879,545	2,660,719
20	TOTAL Maintenance *(Enter Total of Lines 15 thru 19)*	27,385,363	40,873,161
21	TOTAL Power Production Expenses-Steam Power *(Total of lines 13 & 20)*	435,585,429	434,871,489
22	**B. Nuclear Power Generation**		
23	Operation		
24	(517) Operation Supervision and Engineering	16,879,511	19,469,804
25	(518) Fuel	159,132,153	159,326,773
26	(519) Coolants and Water	5,310,279	6,135,422
27	(520) Steam Expenses	9,761,297	10,775,472
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred - **CR**		
30	(523) Electric Expenses	2,212,555	2,536,554
31	(524) Miscellaneous Nuclear Power Expenses	86,689,774	76,857,163
32	(525) Rents	0	0
33	TOTAL Operation *(Enter Total of lines 24 thru 32)*	279,985,569	275,101,188
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	12,052,181	11,924,259
36	(529) Maintenance of Structures	2,520,038	3,192,035
37	(530) Maintenance of Reactor Plant Equipment	62,577,064	74,650,363
38	(531) Maintenance of Electric Plant	2,872,540	22,854,776
39	(532) Maintenance of Miscellaneous Nuclear Plant	18,320,357	21,400,375
40	TOTAL Maintenance *(Enter Total of Lines 35 thru 39)*	98,342,180	134,021,808
41	TOTAL Power Production Expenses-Nuclear Power *(Total of lines 33 & 40)*	378,327,749	409,122,996
42	**C. Hydraulic Power Generation**		
43	Operation		
44	(535) Operation Supervision and Engineering	614,674	438,870
45	(536) Water for Power	0	37,544
46	(537) Hydraulic Expenses	28,282	40,367
47	(538) Electric Expenses	617	1,343
48	(539) Miscellaneous Hydraulic Power Generation Expenses	1,068,418	823,630
49	(540) Rents	0	0
50	TOTAL Operation *(Enter Total of Lines 44 thru 49)*	1,711,991	1,341,754
51	Maintenance		
52	(541) Maintenance Supervision and Engineering	118,972	204,136
53	(542) Maintenance of Structures	368,042	79,201
54	(543) Maintenance of Reservoirs, Dams, and Waterways	716,830	880,625
55	(544) Maintenance of Electric Plant	420,584	675,752
56	(545) Maintenance of Miscellaneous Hydraulic Plant	36,304	86,815
57	TOTAL Maintenance *(Total of Lines 52 thru 56)*	1,660,732	1,926,529

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2012

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (cont'd)

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

Line No.	Account (a)	Amt. For Current Year (b)	Amt. For Previous Year (c)
58	**C. Hydraulic Power Generation (Continued)**		
59	TOTAL Pwr. Production Expenses-Hydraulic Pwr.*(Total of lines 50 & 57)*	3,372,723	3,268,283
60	**D. Other Power Generation**		
61	Operation		
62	(546) Operation Supervision and Engineering	39,699	23,870
63	(547) Fuel	64	(5)
64	(548) Generation Expenses	(15)	(13)
65	(549) Miscellaneous Other Power Generation Expenses	14,554	21,858
66	(550) Rents		
67	TOTAL Operation *(Total of Lines 62 thru 66)*	54,302	45,710
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures		
71	(553) Maintenance of Generating and Electric Plant	(19)	(20)
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	0	0
73	TOTAL Maintenance *(Total of Lines 69 thru 72)*	(19)	(20)
74	TOTAL Pwr. Production Expenses-Other Power *(Total of Lines 67 & 73)*	54,283	45,690
75	**E. Other Power Supply Expenses**		
76	(555) Purchased Power	530,902,651	510,536,100
77	(556) System Control and Load Dispatching	1,616,100	1,742,725
78	(557) Other Expenses	4,996,816	6,490,781
79	Total Other Power Supply Expenses *(Total of Lines 76 thru 78)*	537,515,567	518,769,606
80	Total Pwr. Production Expenses *(Total of lines 21, 41, 59, 74 & 79)*	1,354,855,751	1,366,078,064
81	**2. TRANSMISSION EXPENSES**		
82	Operation		
83	(560) Operation Supervision and Engineering	2,141,577	1,890,535
84	(561) Load Dispatching		
85	(561.1) Load Dispatch-Reliability	17,920	18,751
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,172,559	1,336,334
87	(561.3) Load Dispatch-Transmission Service and Scheduling	(246)	25
88	(561.4) Scheduling, System Control and Dispatch Services	5,531,795	5,167,862
89	(561.5) Reliability, Planning and Standards Development	327,367	290,402
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	1,083,397	1,059,859
93	(562) Station Expenses	790,946	741,793
94	(563) Overhead Lines Expenses	151,087	355,042
95	(564) Underground Lines Expenses	0	0
96	(565) Transmission of Electricity by Others	13,667,883	7,816,222
97	(566) Miscellaneous Transmission Expenses	3,551,568	2,220,458
98	(567) Rents	28,321	17,871
99	TOTAL Operation *(Total of Lines 83 thru 98)*	28,464,174	20,915,154
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	103,039	114,341
102	(569) Maintenance of Structures	60,724	85,538
103	(569.1) Maintenance of Computer Hardware	122,732	178,112
104	(569.2) Maintenance of Computer Software	623,152	744,816
105	(569.3) Maintenance of Communication Equipment	190,134	368,690
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	3,838,482	3,929,582
108	(571) Maintenance of Overhead Lines	6,623,668	8,123,002
109	(572) Maintenance of Underground Lines	(6)	44,894
110	(573) Maintenance of Miscellaneous Transmission Plant	0	0
111	TOTAL Maintenance *(Total of Lines 101 thru 110)*	11,561,925	13,588,975
112	TOTAL Transmission Expenses *(Total of Lines 99 & 111)*	40,026,099	34,504,129
113	**3. REGIONAL MARKET EXPENSES**		
114	Operation		

Name of Respondent	This Report Is:	Date of Report	Year of Report
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ELECTRIC OPERATION AND MAINTENANCE EXPENSES (cont'd)

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

Line No.	Account (a)	Amt. For Current Year (b)	Amt. For Previous Year (c)
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	5,602,674	5,248,935
122	(575.8) Rents		
123	TOTAL Operation *(Total of Lines 115 thru 122)*	5,602,674	5,248,935
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 *(Total of Lines 125 thru 129)*	0	0
131	TOTAL Distribution Expenses *(Total of Lines 123 & 130)*	5,602,674	5,248,935
132	**4. DISTRIBUTION EXPENSES**		
133	Operation		
134	(580) Operation Supervision and Engineering	3,038,309	3,602,470
135	(581) Load Dispatching	1,129,568	1,132,506
136	(582) Station Expenses	1,139,861	996,875
137	(583) Overhead Line Expenses	279,332	1,153,719
138	(584) Underground Line Expenses	1,950,941	1,918,088
139	(585) Street Lighting and Signal System Expenses	135,955	100,442
140	(586) Meter Expenses	(450,431)	947,539
141	(587) Customer Installations Expenses	576,407	546,581
142	(588) Miscellaneous Expenses	14,868,403	2,927,929
143	(589) Rents	1,827,905	1,865,800
144	TOTAL Operation *(Total of Lines 134 thru 143)*	24,496,250	15,191,949
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	159,921	155,142
147	(591) Maintenance of Structures	103,512	84,020
148	(592) Maintenance of Station Equipment	2,902,721	2,908,629
149	(593) Maintenance of Overhead Lines	23,066,871	27,807,703
150	(594) Maintenance of Underground Lines	1,836,091	1,871,679
151	(595) Maintenance of Line Transformers	450,603	610,051
152	(596) Maintenance of Street Lighting and Signal Systems	469,120	475,540
153	(597) Maintenance of Meters	202,507	227,822
154	(598) Maintenance of Miscellaneous Distribution Plant	365,173	899,040
155	TOTAL Maintenance *(Total of Lines 146 thru 154)*	29,556,519	35,039,626
156	TOTAL Distribution Expenses *(Total of Lines 144 & 155)*	54,052,769	50,231,575
157	**5. CUSTOMER ACCOUNTS EXPENSES**		
158	Operation		
159	(901) Supervision	1,057,730	1,519,090
160	(902) Meter Reading Expenses	2,310,484	3,010,865
161	(903) Customer Records and Collection Expenses	14,604,947	15,820,807
162	(904) Uncollectible Accounts	321,027	157,447
163	(905) Miscellaneous Customer Accounts Expenses	39,116	130,082
164	TOTAL Customer Accounts Expenses *(Total of Lines 159 thru 163)*	18,333,304	20,638,291
165	**6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES**		
166	Operation		
167	(907) Supervision	919,850	1,120,374
168	(908) Customer Assistance Expenses	19,876,898	14,686,377
169	(909) Informational and Instructional Expenses	562	6,407
170	(910) Miscellaneous Customer Service and Informational Expenses	599	23
171	TOTAL Cust. Service and Informational Exp. *(Total of Lines 167 thru 170)*	20,797,909	15,813,181

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2012

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (cont'd)

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

Line No.	Account (a)	Amt. For Current Year (b)	Amt. For Previous Year (c)
172	**7. SALES EXPENSE**		
173	Operation		
174	(911) Supervision	480	37
175	(912) Demonstrating and Selling Expenses	222,714	120,365
176	(913) Advertising Expenses	390	1,981
177	(916) Miscellaneous Sales Expenses		
178	Total Sales Expenses *(Total of Lines 174 thru 177)*	223,584	122,383
179	**8. ADMINISTRATIVE AND GENERAL EXPENSES**		
180	Operation		
181	(920) Administrative and General Salaries	26,678,857	26,005,132
182	(921) Office Supplies and Expenses	3,076,383	3,750,733
183	(Less) (922) Administrative Expenses Transferred - **CR**	4,966,861	4,221,330
184	(923) Outside Services Employed	24,930,210	26,538,028
185	(924) Property Insurance	4,407,050	3,615,009
186	(925) Injuries and Damages	6,444,620	7,188,172
187	(926) Employee Pensions and Benefits	37,817,551	38,464,933
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	13,085,376	12,528,390
190	(929) (Less) Duplicate Charges - **CR.**	370,156	748,783
191	(930.1) General Advertising Expenses	276,915	288,023
192	(930.2) Miscellaneous General Expenses	5,318,780	4,661,707
193	(931) Rents	6,755,425	6,675,670
194	TOTAL Operation *(Total of Lines 181 thru 193)*	123,454,150	124,745,684
195	Maintenance		
196	(935) Maintenance of General Plant	4,055,727	4,433,021
197	TOTAL Administrative and General Expenses *(Total of Lines 194 & 196)*	127,509,877	129,178,705
198	TOTAL Electric Operation and Maintenance Expenses *(Enter total*	1,621,401,967	1,621,815,263
199	*of lines 80, 112, 131, 156, 164, 171, 178, and 197*)		

NUMBER OF ELECTRIC DEPARTMENT EMPLOYEES

1. The data on number of employees should be reported for the payroll period ending nearest to October 31, or any payroll period ending 60 days before or after October 31.

2. If the respondent's payroll for the reporting period includes any special construction personnel, include such employees on line 3, and show the number of such special construction employees in a footnote.

3. The number of employees assignable to the electric department from joint functions of combination utilities may be determined by estimate, on the basis of employee equivalents. Show the estimated number of equivalent employees attributed to the electric department from joint functions.

1. Payroll Period Ended (Date)	12/31/2012	12/31/2011
2. Total Regular Full-Time Employees	2,627	2,649
3. Total Part-Time and Temporary Employees	10	6
4. Total Employees	2,637	2,655

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Indiana Michigan Power Company	(2) [ ] A Resubmission		December 31, 2012

FOOTNOTE DATA

Page Number (a)	Line Number (b)	Column Number (c)	Comments (d)
320	5	b	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.
320	25	b	The portion of account 518 that is excluded from the nuclear fuel costs in I&M's generation formula rate is identified by a query of the general ledger.
320	31	b	The portion of account 524 representing ARO expenses that are excluded from non-fuel generation O&M in I&M's 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 Indian Utility Regulatory Commission.
320	93	b	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 and 353 multiplied by the balance in O&M accounts 562, 569,and 570.
320	103	b	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.
320	185	b	The insurance expenses for generation included in I&M's generation formula rate are identified by a query from the general ledger.

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PURCHASED POWER (Account 555)
(Including power exchanges)

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.

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) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	AEP GENERATING COMPANY	RQ	AEG 1			
2	AEP SERVICE CORPORATION	OS	17			
3	AEP SERVICE CORPORATION	OS	20			
4	ALLEN FAMILY LIMITED PARTNERSHIP	OS				
5	AMEREN ENERGY MARKETING	OS				
6	AMERICAN MUNICIPAL POWER	OS				
7	ASSOCIATED ELECT COOPERATIVE	OS				
8	BARCLAYS BANK PLC	OS				
9	BEECH RIDGE ENERGY LLC	OS				
10	BP AMOCO	OS				
11	BP ENERGY COMPANY	OS				
12	BUCKEYE RURAL ELECTRIC ADMIN	OS				
13	CHARLESTON CLEAN ENERGY	OS				
14	CONSTELLATION ENGY COMMODITIES	OS				
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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. Report in columns (h) and (i) 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 (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (1) 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 column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
6,572,514			95,961,785	142,903,670		238,865,455	1
4,095,792			18,221,412	129,280,260		147,501,672	2
1,333				36,030		36,030	3
				-2		-2	4
			5,454			5,454	5
8,415				375,509		375,509	6
1,257				35,797		35,797	7
				224,891		224,891	8
				-35,070		-35,070	9
				-30,322		-30,322	10
				-19,387		-19,387	11
				503,460		503,460	12
				4		4	13
55,151			1,006,160	1,629,354		2,635,514	14
13,483,639			143,249,451	387,653,200		530,902,651	

PURCHASED POWER (Account 555)
(Including power exchanges)

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.

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) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	DP&L POWER SERVICES	OS				
2	DUKE ENERGY CAROLINAS, LLC	OS				
3	DYNEGY POWER MARKETING INC.	OS				
4	EAST KY POWER CO-OP POWER	OS				
5	EDF TRADING NORTH AMERICA LLC	OS				
6	ENERGY AMERICA	OS				
7	ENTERGY POWER SERVICES	OS				
8	EXELON GENERATION - POWER TEAM	OS				
9	FOWLER RIDGE II WIND FARM LLC	OS				
10	FOWLER RIDGE WIND FARM LLC	OS				
11	FRENCH PAPER	OS				
12	FT. WAYNE ELECTRIC JATC	OS				
13	J ARON AND COMPANY	OS				
14	JP MORGAN VENTURES ENERGY CORP	OS				
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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. Report in columns (h) and (i) 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 (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) 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 column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
				34,216		34,216	1
16				1,171		1,171	2
			9,441			9,441	3
167				4,331		4,331	4
			19,447			19,447	5
				80,044		80,044	6
908				21,682		21,682	7
				1,403,967		1,403,967	8
138,921				10,876,952		10,876,952	9
246,543				14,469,605		14,469,605	10
1,882				54,329		54,329	11
2				43		43	12
				-36,118		-36,118	13
			64,292			64,292	14
13,483,639			143,249,451	387,653,200		530,902,651	

PURCHASED POWER (Account 555)
(Including power exchanges)

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.

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): Average Monthly NCP Demand (e)	Actual Demand (MW): Average Monthly CP Demand (f)
1	LG&E UTILITIES POWER SALES	OS				
2	MIDWEST ISO	OS				
3	MIZUHO SECURITIES USA INC	OS				
4	NATIONAL POWER COOPERATIVE INC	OS				
5	NC ELECTRIC MEMBERSHIP CORP.	OS				
6	NEXTERA ENERGY POWER MKTG LLC	OS				
7	NRG POWER MARKETING	OS				
8	NO CAROLINA MUNI PWR AGENCY	OS				
9	OLD DOMINION ELECTRIC	OS				
10	OVEC POWER SCHEDULING	OS				
11	PJM INTERCONNECTION	OS				
12	RANDOLPH SCHOOLS	OS				
13	SOUTHERN MARYLAND ELEC COOP INC	OS				
14	SOUTHERN COMPANY	OS				
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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. Report in columns (h) and (i) 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 (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) 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 column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
1,788				78,280		78,280	1
5,845			1	164,490		164,491	2
				303,110		303,110	3
17,305			71,644	1,245,978		1,317,622	4
110				4,212		4,212	5
				164,446		164,446	6
146				5,250		5,250	7
3				86		86	8
277				9,280		9,280	9
768,979			26,061,658	23,117,262		49,178,920	10
1,433,248			1,813,029	57,205,617		59,018,646	11
				71,214		71,214	12
228				7,500		7,500	13
20				1,111		1,111	14
13,483,639			143,249,451	387,653,200		530,902,651	

PURCHASED POWER (Account 555)
(Including power exchanges)

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.

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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.

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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.

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) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	THE ENERGY AUTHORITY	OS				
2	TVA BULK POWER TRADING	OS				
3	UBS SECURITIES LLC	OS				
4	WABASH VALLEY POWER ASSN INC.	OS				
5	WILLIAM E RICHTER	OS				
6	WIISCONSIN POWER AND LIGHT	OS				
7	WISCONSIN ELECTRIC POWER CO	OS				
8	WPPI ENERGY	OS				
9	ADJUSTMENTS					
10						
11						
12						
13						
14						
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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. Report in columns (h) and (i) 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 (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) 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 column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
17,588				744,572		744,572	1
115,199				2,615,776		2,615,776	2
				984,291		984,291	3
			3			3	4
2				64		64	5
			8,521			8,521	6
			2,027			2,027	7
			4,577			4,577	8
				-883,755		-883,755	9
							10
							11
							12
							13
							14
13,483,639			143,249,451	387,653,200		530,902,651	

Schedule Page: 326 Line No.: 1 Column: a

Affiliated Company

Schedule Page: 326 Line No.: 2 Column: a

Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company and Ohio Power Company are associated companies and members of the American Electric Power System Power Pool, whose electric facilities are interconnected at a number of points and are operated in a fully coordinated manner on a system pool basis. Power transactions between the members of the AEP System Pool are governed by the terms of the interconnection agreement dated July 6, 1951, as amended, and are processed by American Electric Power Service Corporation.

Schedule Page: 326 Line No.: 3 Column: a

Affiliated Company - transactions related to the System Integration Agreement. See pages 122-123 (Notes to Financial Statements) Related Party Transactions - System Integration Agreement for additional information.

Schedule Page: 326.3 Line No.: 9 Column: a

Reclassification between 447 and 555 accounts to incorporate certain trading/marketing activity. The amounts represented on Page 310-11 and 326-27 are equal and off-setting.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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.

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 Classifi-cation (d)
1	PJM Network Integration	Various	Various	FNO
2	Transmission Service -NonAffil			
3				
4	PJM Network Integration Trans	Various	Various	FNO
5	Revenues-Whlsl Cust-NonAffil			
6				
7	PJM Network Integration Revenue-Affiliated	Various	Various	FNS
8				
9	PJM Point to Point	Various	Various	LFP
10	Transmission Service -NonAffil			
11				
12	PJM Trans Owner Service Revenue	Various	Various	OLF
13	Wholesale Customer - NonAffil			
14				
15	PJM Transmission Owner	Various	Various	OLF
16	Admin Revenue - Non Affiliated			
17				
18	PJM Transmission Distribution	Various	Various	OS
19	& Metering - Non Affiliated			
20				
21	PJM Expansion Cost Recovery	Various	Various	OS
22				
23	RTO Formation Cost Recovery	Various	Various	OS
24				
25	PJM Power Factor Credits Revenue	Various	Various	OS
26	Wholesale Customers-NonAffil			
27				
28	PJM Transmission Enhancement	Various	Various	FNO
29	Revenue - Non Affiliated			
30				
31	PJM Transmission Enhancement	Various	Various	FNS
32	Revenue - Affiliated			
33				
34	SECA Transmission Revenue	Various	Various	OS
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

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.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
PJM OATT	Various	Various				1
						2
						3
PJM OATT	Various	Various				4
						5
						6
PJM OATT	Various	Various				7
						8
PJM OATT	Various	Various				9
						10
						11
PJM OATT	Various	Various				12
						13
						14
PJM OATT	Various	Various				15
						16
						17
PJM OATT	Various	Various				18
						19
						20
PJM OATT	Various	Various				21
						22
PJM OATT	Various	Various				23
						24
PJM OATT	Various	Various				25
						26
						27
PJM OATT	Various	Various				28
						29
						30
PJM OATT	Various	Various				31
						32
						33
PJM OATT	Various	Various				34
			0	0	0	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

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 (11011) 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.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
23,855,800			23,855,800	1
				2
				3
5,973,358			5,973,358	4
				5
				6
744,750			744,750	7
				8
1,824,443			1,824,443	9
				10
				11
	66,524		66,524	12
				13
				14
	430,672		430,672	15
				16
				17
		528,232	528,232	18
				19
				20
337,271			337,271	21
				22
145,455			145,455	23
				24
		157,849	157,849	25
				26
				27
433,905			433,905	28
				29
				30
13,052			13,052	31
				32
				33
		561,667	561,667	34
33,328,034	**497,196**	**1,247,748**	**35,072,978**	

Schedule Page: 328 Line No.: 1 Column: e

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.

Schedule Page: 328 Line No.: 18 Column: m

Per Proforma ILDSA (Interconnection and Local Delivery Service Agreement) AEP Tariff 3rd Revised Volume No. 6.

Schedule Page: 328 Line No.: 25 Column: m

Per Proforma ILDSA AEP Tariff 3rd Revised Volume No. 6.

Schedule Page: 328 Line No.: 34 Column: m

See "Seams Elimination Cost Allocation (SECA) Revenue Subject to Refund" in footnote #2 Rate Matters Notes to Financial Statements.

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2012

SALES TO RAILROADS AND RAILWAYS AND INTERDEPARTMENTAL SALES (Accounts 446, 448)

1. Report particulars concerning sales included in Accounts 446 and 448.
2. For Sales to Railroads and Railways, Account 446, give name of railroad or railway in addition to other required information. If contract covers several points of delivery and small amounts of electricity are delivered at each point, such sales may be grouped.
3. For Interdepartmental Sales, Account 448, give name of other department and basis of charge to other department in addition to other required information.
4. Designate associated companies.
5. Provide subheading and total for each account.

Line No.	Item (a)	Point of Delivery (b)	Kilowatt-hours (c)	Revenue (d)	Revenue per kwh (in cents) (e)
1	None				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					

RENT FROM ELECTRICITY PROPERTY AND INTERDEPARTMENTAL RENTS (Accounts 454, 455)

1. Report particulars concerning rents received included in Accounts 454 and 455.
2. Minor rents may be grouped by classes.
3. If rents are included which were arrived at under an arrangement for apportioning expenses of a joint facility, whereby the amount included in this account represents profit or return on property, depreciation and taxes, give particulars and the basis of apportionment of such charges to Accounts 454 and 455.
4. Designate if lessee is an associated company.
5. Provide a subheading and total for each account.

Line No.	Name of Lessee or Department (a)	Description of Property (b)	Amount of Revenue for Year (c)
16	Acct 454 - Rents from Electric Property - Michigan		
17	Miscellaneous Lessees	Pole Contact Rental	954,057
18	American Electric Power Service Corporation **	Benton Harbor Service Center	9,932
19	Miscellaneous Lessees	Agricultural, Commercial, & Residential	103,951
20			
21			
22	Total Acct 454		1,067,940
23			
24	Acct 455	None	
25			
26			
27	** Affiliated Entity		
28			
29			

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A resubmission	(Mo, Da, Yr)	December 31, 2012

SALES OF WATER AND WATER POWER (Account 453)

1. Report below the information called for concerning revenues derived during the year from sales to others of water or water power.
2. In column (c) show the name of the power development of the respondent supplying the water or water power sold.
3. Designate associated companies.

Line No.	Name of Purchaser (a)	Purpose for Which Water Was Used (b)	Power Plant Development Supplying Water or Water Power (c)	Amount of Revenue for Year (e)
1	None			
2				
3				
4				
5				
6				
7				
8				
9				
10	TOTAL			0

MISCELLANEOUS SERVICE REVENUES AND OTHER ELECTRIC REVENUES (Accounts 451, 456)

1. Report particulars concerning miscellaneous service revenues and other electric revenues derived from electric utility operations during year. Report separately in this schedule the total revenues from operation of fish and wildlife and recreation facilities, regardless of whether such facilities are operated by company or by contract concessionaires. Provide a subheading and total for each account. For Account 456, list first revenues realized through Research and Development ventures, see Account 456.
2. Designate associated companies.
3. Minor items may be grouped by classes.

Line No.	Name of Company and Description of Service (a)	Amount of Revenue for Year (b)
11	Acct 451 - Miscellaneous Service Revenues - Michigan	
12	Other	738,140
13		
14	Acct 456 - Other Electric Revenues - Michigan	
15	Associated Business Development	198,653
16		
17	Adjustment of Insurance Proceeds	(200,000)
18		
19	Michigan Net Lost Revenue	503,999
20		
21	PJM/RTO Cost Recovery Items	5,807,566
22		
23		
24		
25		
26		
27		
28		
29		
30	TOTAL	7,048,358

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

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 Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	PJM	OS					13,667,883	13,667,883
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL						13,667,883	13,667,883

Schedule Page: 332 Line No.: 1 Column: b

Transmission Enhancement Charges and Credits (PJM OATT Schedule 12)
Network Integration Transmission Service Charges - NITS (PJM OATT Schedule H)
Transmission Owner Service (PJM OATT Tariff Sixth Revised Volume No. 1)

Name of Respondent	This Report Is:	Date of Report	Year of Report
INDIANA MICHIGAN POWER COMPANY - MICHIGAN	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	12/31/2012

LEASE RENTALS CHARGED

1. For purposes of this schedule a "lease" is defined as a contract or other agreement by which one party (lessor conveys an intangible right or land or other tangible property and equipment to another lessee) for a specified period of one year or more for rent.

2. Report below, for leases with annual charges of $25,000 or more, but less than $250,000, the data called for in columns a, b (description only), f, g, and j.

3. For leases having annual charges of $250,000 or more, report the data called for in all the columns below.

4. The annual charges referred to in instruction 1 and 2 include the basic lease payment and other payments to or in behalf of the lessor such as taxes, depreciation, assumed interest or dividends on the lesser Securities, cost of property replacements ** and other expenditures with respect to leased property except the expenses paid by lessee are to be itemized in column f below.

5. Leases of construction equipment in connection with construction work in progress are not required to be reported herein. Continuous, master or open-end leases fof EDP or office equipment, automobile fleets and other equipment that is short-lived and replaced under terms of the lease or for pole rentals shall report only the data called for in columns a, b (description only), f, g and j. unless the lessee has the option to purchase the property.

6. In column a report the name of the

A. LEASE RENTAL CHARGED TO ELECTRIC OPERATING EXPENSES

Name of Lessor (a)	Basic Details of Lease (b)	Terminal Dates of Lease, Primary (P) or Rental (R) (c)
GE Capital Commercial Inc (GE)	Office Furniture and Equipment and Transportation Equipment (2)	
Huntington Bank	Office Furniture and Equipment and Transportation Equipment (2)	
RBS Asset Finance	Office Furniture and Equipment and Transportation Equipment (2)	

Name of Respondent INDIANA MICHIGAN POWER COMPANY - MICHIGAN	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report 12/31/2012

LEASE RENTALS CHARGED (Continued)

lessor. List lessors that are associated companies * (describing association) first, followed by non-associated lessors. * See definition on page 226 (B)

7. In column (b) for each leasing arrangement, report in order, classified by generating station, transmission line, distribution system, large substation, or other operating unit or system, followed by any other leasing arrangements not covered under the preceding classifications:
Description of the property, whether the lease is a sale and leaseback, whether leasee has option to purchase and conditions of purchase, whether lease is cancellable by either party and the cancellation conditions, state the tax treatment used and the accounting treatment of the lease payments (levelized charges to expense or other treatment), the basis of any charges apportioned between the lessor and lessee, and the responsibility of the respondent for operation and maintenance expences and replacement of property.

The above information is to be reported with initiation of the lease and thereafter when changed or every five years, which ever occurs first.

8. Report in column (d), as of the date of the current lease term, the original cost of the property leased, estimate if not known, or the fair market value of the property if greater than the original cost and indicate as shown. If the leased property is part of a large unit, such as part of a building, indicate without associating any cost or value with it.

9. Report in column (k) below the estimated remaining annual charges under the current term of the lease. Do not apply a present value to the estimate. Assume that cancellable leases will not be cancelled when estimating the remaining charges.

A. LEASE RENTAL CHARGED TO ELECTRIC OPERATING EXPENSES (Continued)

Orginal Cost (O) or Fair Market Value (D) of Property (d)	Expense to be Paid By Lessee Itemize (e)	Amount of Rent - Current Term: Current Year: Lessor (f)	Other (g)	Lessor (h)	Other (i)	Account Charged (j)	Remaining Annual Charges Under Lease Est. If Not Known (k)
		12,180				506	
		13,321				524	
		1,332				566	
		1,986				571	
		73,804				588	
		96,609				931	
		175				935	
		89,232				501	
		44,041				506	
		37,051				514	
		1,152,518				524	
		7,575				566	
		141,347				588	
		268,554				931	
		14,709				935	
		181,599				501	
		39				901	

Name of Respondent INDIANA MICHIGAN POWER COMPANY - MICHIGAN	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report 12/31/2012

A. LEASE RENTAL CHARGED TO ELECTRIC OPERATING EXPENSES (Continued)

Name of Lessor (a)	Basic Details of Lease (b)	Terminal Dates of Lease, Primary (P) or Rental (R) (c)
Blue Jay Associates	Fort Wayne General Service Center BLDG225 (1) LPM1853 Date of Lease: 5-1-71 1. This is a sale and leaseback 2. Lessee has option to purchase under varying conditions depending on the status of the premises 3. Lease may be cancelled by either party in event of change of status of the premises 4. Respondent is responsible for all operation and maintenance expenses.	
SS Properties Associates	Muncie Service Building BLDG218 LPM1863 (1) Date of Lease: 5-26-72 1. This is a sale and leaseback 2. Lessee has option to purchase under varying conditions depending on the status of the premises 3. Lease may be cancelled by either party in event of change of status of the premises 4. Respondent is responsible for all operation and maintenance expenses.	

Name of Respondent INDIANA MICHIGAN POWER COMPANY - MICHIGAN	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report 12/31/2012

A. LEASE RENTAL CHARGED TO ELECTRIC OPERATING EXPENSES (Continued)

Orginal Cost (O) or Fair Market Value (D) of Property (d)	Expense to be Paid By Lessee Itemize (e)	Amount of Rent - Current Term Current Year Lessor (f)	Other (g)	Lessor (h)	Other (i)	Account Charged (j)	Remaining Annual Charges Under Lease Est. If Not Known (k)
	Real Estate taxes, assessments, maintenance, alterations, replacements and additions, insurance, and utilities.	86,352				931	
	Real Estate taxes, assessments, maintenance, alterations, replacements and additions, insurance, and utilities.	73,750				931	

Name of Respondent INDIANA MICHIGAN POWER COMPANY - MICHIGAN	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report 12/31/2012

A. LEASE RENTAL CHARGED TO ELECTRIC OPERATING EXPENSES (Continued)

Name of Lessor (a)	Basic Details of Lease (b)	Terminal Dates of Lease, Primary (P) or Rental (R) (c)
Slater Associates	South Bend Service Building BLDG235 Ls# 558 (1) LPM2389 Date of Lease: 10-1-79 1. This is a sale and leaseback 2. Lessee has option to purchase under varying conditions depending on the status of the premises 3. Lease may be cancelled by either party in event of change of status of the premises 4. Respondent is responsible for all operation and maintenance expenses.	12/31/2014
Aetna Life Insurance Co. and One Summit Associates	Fort Wayne General Office Building- One Summit Square (1) Date of Lease: 10-25-78 BLDG227 Ls# 2059 LPM2688 1. This is a sale and leaseback 2. Lessee has option to purchase under varying conditions depending on the status of the premises 3. Lease is noncancellable 4. Respondent is responsible for all operation and maintenance expenses.	10/23/2013
West Ohio II, LLC	State President Office - Indiana, LPM2448 Date of Lease: 1/17/2000 1. This is not a sale and leaseback 2. Lease does not have an option to purchase 3. Lease may be cancelled under certain conditions	
U.S. Bank Trust N.A.	Rockport Generating Plant Unit 2 Date of Lease: 12/7/89 1. This is a sale and leaseback 2. No purchase option 3. Lease may be cancelled under certain conditions 4. Respondent is responsible for all operation and maintenance expenses.	12/07/22 (P)

Name of Respondent	This Report Is:	Date of Report	Year of Report
INDIANA MICHIGAN POWER COMPANY - MICHIGAN	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	12/31/2012

A. LEASE RENTAL CHARGED TO ELECTRIC OPERATING EXPENSES (Continued)

Orginal Cost (O) or Fair Market Value (D) of Property	Expense to be Paid By Lessee Itemize	Amount of Rent - Current Term				Account Charged	Remaining Annual Charges Under Lease Est. If Not Known
		Current Year					
		Lessor	Other	Lessor	Other		
(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
5,225,000	Real Estate taxes,			1,183,277		567	
	assessments, maintenance,			1,808,390		588	
	alterations, replacements			2,517,082		589	
	and additions, insurance,			111,802		921	
	and utilities.			698,760		184	
		537,500		7,068,205		931	1,209,375
44,668,660	Real Estate taxes,			-22		506	
	assessments, maintenance,			1,801,102		566	
	alterations, replacements			4,829,851		567	
	and additions, insurance,			4,561,517		588	
	and utilities.			2,450,128		589	
				6,325,888		921	
		5,042,487		72,688,335		931	19,329,531
				5,479,250		184	
	Maintenance, alterations, replacements, additions and insurance	62,826				931	
850,000,000	All expenses necessary to operate, maintain, preserve and keep the leased property in good working order. Also responsible for taxes and insurance.	73,853,988		1,701,997,594	26,654,952	507	133,576,577

Name of Respondent INDIANA MICHIGAN POWER COMPANY - MICHIGAN	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report 12/31/2012

A. LEASE RENTAL CHARGED TO ELECTRIC OPERATING EXPENSES (Continued)

Name of Lessor (a)	Basic Details of Lease (b)	Terminal Dates of Lease, Primary (P) or Rental (R) (c)
Blue Jay Associates	D.C. Cook Nuclear Plant Visitor's Center BLDG248, LPM1862 Date of Lease: 5-1-71 1. This is not a sale and leaseback 2. Lessee has option to purchase under varying conditions depending on the status of the premises 3. Lease may be cancelled by either party in event of change of status of the premises 4. Respondent is responsible for all operation and maintenance expenses.	
Benton Associates	Benton Harbor Service Building BLDG237 LPM1864 (1) Date of Lease: 7-15-72 (formerly St Joe Serv Ctr) 1. This is a sale and leaseback 2. Lessee has option to purchase under varying conditions depending on the status of the premises 3. Lease may be cancelled by either party in event of change of status of the premises 4. Respondent is responsible for all operation and maintenance expenses.	
Green, B.G. & Teresa	New Buffalo Service Center BLDG247 Ls# 2058	
American Tower, LP	Milan Telecom Site	
Global Tower, LLC	Butler Telecom	
Capital Tower LLC	Lansing Office LPM9010	
	NOTES: (1) Apportionment based on percentage of floor space occupied. (2) Apportionment based on percentage of equipment usage. (3) Charged directly to operating expense of barging operation. Tax treatment: Treated as lease, rental payments are deducted for federal income tax purposes. Accounting treatment: Leasing rentals distributed to benefiting accounts as incurred based on accrual method.	

Name of Respondent INDIANA MICHIGAN POWER COMPANY - MICHIGAN	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report 12/31/2012

A. LEASE RENTAL CHARGED TO ELECTRIC OPERATING EXPENSES (Continued)

Orginal Cost (O) or Fair Market Value (D) of Property (d)	Expense to be Paid By Lessee Itemize (e)	Amount of Rent - Current Term Current Year Lessor (f)	Other (g)	Lessor (h)	Other (i)	Account Charged (j)	Remaining Annual Charges Under Lease Est. If Not Known (k)
		83,920				931	
		59,813				931	
		57,291				931	
		36,947				935	
		44,366				935	
		54,271				931	
	Total Section A	82,129,583					

Name of Respondent INDIANA MICHIGAN POWER COMPANY - MICHIGAN	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report 12/31/2012

B. OTHER LEASE RENTALS CHARGED (Such as to Deferred Debits, etc.)

Name of Lessor (a)	Basic Details of Lease (b)	Terminal Dates of Lease, Primary (P) or Rental (R) (c)
GE Capital Commercial Inc (GE)	Office Furniture and Equipment and Transportation Equipment (2)	
Huntington Bank	Office Furniture and Equipment and Transportation Equipment (2)	
RBS Operating Co	Transportation Equipment	
Renaissance Capital Alliance LLC	Transportation Equipment	
BTMU Capital	Railcar Lease formally with AEP Transportation Wilmington Trust as Security Trustee (Lease 4084)	06/30/2023
Wilmington Trust Co.	Railcars Trust 2004-A (Lease 3616)	12/15/2024
U.S. Bank Trust N.A.	Railcars Trust 94-1 (Lease 3708) Railcars Trust 91-5 (Lease 4490) - Renewal of 00736 Railcars Trust 91-3 (Lease 4461) - Renewal of 00735 Railcars Trust 91-2 (Lease 4462) - Renewal of 3702	12/30/2014 12/31/2016 9/30/2016 9/30/2016
Citicorp North America, Inc	Cook Plant Warehouse, LPM9326, Ls# 3171 Date of Lease: 3/15/02	03/14/2012
Pitney Bowes	Water Transportation Equipment	10/1/2014
Wilmington Trust	Water Transportation Equipment	04/01/2015
State Street Bank	Water Transportation Equipment	07/01/2013
CIT Group/Equipment Financing, Inc.	Water Transportation Equipment (3) Date of Lease: 03/01/88, 02/01/89, 10/01/90, & 04/01/93 1. This is not a sale and leaseback. 2. Lessee has an option to purchase any or all of the vessels at the end of the original charter period or any extension thereof at a purchase price equal to the fair market value of the vessels at such date. 3. Lessee has option to terminate this lease subject to certain conditions. 4. Respondent is responsible for all operation and maintenance expenses.	01/01/2013 (P)

Name of Respondent INDIANA MICHIGAN POWER COMPANY - MICHIGAN	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report 12/31/2012

B. OTHER LEASE RENTALS CHARGED (Such as to Deferred Debits, etc.) (Continued)

Orginal Cost (O) or Fair Market Value (D) of Property (d)	Expense to be Paid By Lessee Itemize (e)	Amount of Rent - Current Term Current Year Lessor (f)	Other (g)	Lessor (h)	Other (i)	Account Charged (j)	Remaining Annual Charges Under Lease Est. If Not Known (k)
		102,327				107	
		921,514				152	
		2,340,878				184	
		911,885				417	
		117,531				107	
		71,917				152	
		184,685				163	
		7,384				184	
		19,263				152	
		913,718				184	
		68,258				417	
		1,870,551				184	
		1,350,969				186	36,528,029
		16,120				242	
12,271,945		1,841,392		13,628,827		186	30,208,536
8,220,828		1,120,983				186	2,244,871
18,966,753		967,450				186	3,920,186
4,379,951		247,552				186	939,472
17,637,125		1,003,590				186	3,774,613
	Real Estate taxes, assessments, maintenance, alterations, replacements and additions, insurance, and utilities.	64,767				163	
36,397,500		3,694,194		47,278,404		417	
19,030,575		1,495,524		20,524,188		417	
12,656,244		520,120		7,196,079		417	
9,035,000	Taxes except federal & state income, assessments operation and maintenance expenses, altering, replacements and additions, insurance, etc.	832,200		49,187,886		417	

Name of Respondent INDIANA MICHIGAN POWER COMPANY - MICHIGAN	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report 12/31/2012

B. OTHER LEASE RENTALS CHARGED (Such as to Deferred Debits, etc.)

Name of Lessor (a)	Basic Details of Lease (b)	Terminal Dates of Lease, Primary (P) or Rental (R) (c)
RBS Asset Refinance	Water Transportation Equipment	12/30/2022
RBS Asset Refinance	Water Transportation Equipment	01/24/2021
Mitchland LLC (formerly Rashid Bros)	Water Transportation Equipment	07/31/2018
FM, LLC	Water Transportation Equipment	12/31/2016
RBS Asset Refinance	Water Transportation Equipment	08/31/2020
Chase Equipment Leasing	Water Transportation Equipment	01/29/2028
Chase Equipment Leasing	Water Transportation Equipment	06/04/2026
BB&T Finance	Water Transportation Equipment	06/29/2019
Chase Equipment Leasing	Water Transportation Equipment	09/24/2026
Regions Equipment Finance	Water Transportation Equipment	12/17/2019
Manufacturers and Traders Trust Co	Water Transportation Equipment	6/24/2029

Name of Respondent INDIANA MICHIGAN POWER COMPANY - MICHIGAN		This Report Is: (1) [X] An Original (2) [ ] A Resubmission		Date of Report (Mo, Da, Yr)			Year of Report 12/31/2012
B. OTHER LEASE RENTALS CHARGED (Such as to Deferred Debits, etc.) (Continued)							
Orginal Cost (O) or Fair Market Value (D) of Property (d)	Expense to be Paid By Lessee Itemize (e)	Amount of Rent - Current Term Current Year Lessor (f)	Other (g)	Lessor (h)	Other (i)	Account Charged (j)	Remaining Annual Charges Under Lease Est. If Not Known (k)
		2,215,114					
		882,644					
		15,529					
		71,370					
		2,130,530					
		627,765					
		921,725					
		1,174,029					
		1,015,022					
		1,328,256					
		824,403					
	Total Section B	31,891,159					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	3,146,830
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	6,800
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	282
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Associated Business Development	721,838
7	American Electric Power Service Corp Billings	429,553
8	Nuclear Plant Insurance	930,795
9	Corporate Money Pool Allocations	55,522
10	Misc Financing and Legal Expenses	156,689
11	Corporate Contributions and Memberships	120,980
12	Cafeteria Subsidy Expenses	1,373
13	Labor Accruals	2,861
14	River Transport Division Expenses	-566
15	Intercompany Billings	-266,800
16	Minor Items	12,623
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46	TOTAL	5,318,780

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

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 8 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 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			15,123,027		15,123,027
2	Steam Production Plant	28,850,910	848,318	3,962,652		33,661,880
3	Nuclear Production Plant	29,449,316	3,182,659			32,631,975
4	Hydraulic Production Plant-Conventional	1,185,310				1,185,310
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant					
7	Transmission Plant	18,714,918				18,714,918
8	Distribution Plant	38,889,909				38,889,909
9	Regional Transmission and Market Operation					
10	General Plant	2,346,312		1,120,525		3,466,837
11	Common Plant-Electric					
12	TOTAL	119,436,675	4,030,977	20,206,204		143,673,856

B. Basis for Amortization Charges

Section A, Line 1, Column D represents amortization of franchises over the life of the franchise totaling $610,352 and amortization of capitalized software development costs over a 5 year life totaling $14,512,675.

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.

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	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	92,946		11.00	1.63		
14	311 - Rockport U2	3,998		2.00	3.41		
15	311 - Tanners CrkPlant	46,656		9.00	1.31		
16	311 - Tanners Precips	6,874		9.00	1.63		
17	312 - Rockport ACI	11,817		6.00	7.63		
18	312 - Rockport U1	398,265		11.00	1.83		
19	312 - Rockport U2	18,144		2.00	3.64		
20	312 - Tanners CrkPlant	363,846		9.00	2.87		
21	312 - Tanners Crk SNCR	14,152			7.46		
22	312 - Tanners Precips	76,225		9.00	1.65		
23	314 - Rockport U1	87,376		11.00	1.97		
24	314 - Rockport U2	773		2.00	3.90		
25	314 - Tanners CrkPlant	87,896		9.00	1.84		
26	315 - Rockport U1	57,890		11.00	1.68		
27	315 - Rockport U2	2,020		2.00	3.52		
28	315 - Tanners CrkPlant	18,951		9.00	1.66		
29	315 - Tanners Precips	7,885		9.00	1.61		
30	316 - Rockport U1	14,630		11.00	1.97		
31	316 - Rockport U2	6,783		2.00	3.62		
32	316 - Tanners CrkPlant	9,166		9.00	2.87		
33	316 - Tanners Precips	310		9.00	1.59		
34	TOTAL STEAM	1,326,603					
35							
36	NUCLEAR						
37	321 - Cook U1	77,070		1.00	0.78		
38	321 - Cook U2	248,533		1.00	1.11		
39	322 - Cook U1	522,297		1.00	1.55		
40	322 - Cook U2	653,811		2.00	1.34		
41	323 - Cook U1	240,616		2.00	1.51		
42	323 - Cook U2	197,869		2.00	1.15		
43	324 - Cook U1	77,020			1.03		
44	324 - Cook U2	91,917			1.15		
45	325 - Cook U1	27,937		-1.00	1.85		
46	325 - Cook U2	146,919		-1.00	1.63		
47	TOTAL NUCLEAR	2,283,989					
48							
49	HYDRO						
50	331 - Berrien Springs	525		25.00	2.42		

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	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	331 - Buchanan	232		25.00	2.08		
13	331 - Constantine	272		25.00	2.38		
14	331 - Crew Service Cent	417		25.00	1.63		
15	331 - Elkhart	863		25.00	2.69		
16	331 - Mottville	497		25.00	2.67		
17	331 - Twin Branch	533		25.00	2.34		
18	332 - Berrien Springs	5,109		25.00	2.44		
19	332 - Buchanan	4,370		25.00	2.30		
20	332 - Constantine	1,005		25.00	2.43		
21	332 - Elkhart	4,067		25.00	2.73		
22	332 - Mottville	2,188		25.00	2.04		
23	332 - Twin Branch	3,329		25.00	1.79		
24	333 - Berrien Springs	7,125		25.00	3.14		
25	333 - Buchanan	1,292		25.00	2.38		
26	333 - Constantine	743		25.00	2.88		
27	333 - Elkhart	607		25.00	2.24		
28	333 - Mottville	568		25.00	2.43		
29	333 - Twin Branch	5,887		25.00	2.81		
30	334 - Berrien Springs	1,208		25.00	2.87		
31	334 - Buchanan	1,021		25.00	2.79		
32	334 - Constantine	369		25.00	3.77		
33	334 - Elkhart	451		25.00	2.52		
34	334 - Mottville	611		25.00	2.99		
35	334 - Twin Branch	1,623		25.00	2.72		
36	335 - Berrien Springs	790		25.00	3.02		
37	335 - Buchanan	265		25.00	2.94		
38	335 - Constantine	257		25.00	4.14		
39	335 - Crew Service Cent	127		25.00	1.58		
40	335 - Elkhart	184		25.00	3.80		
41	335 - Mottville	194		25.00	3.23		
42	335 - Twin Branch	398		25.00	3.05		
43	336 - Mottville	1		25.00	1.61		
44	TOTAL HYDRO	47,128					
45							
46	TRANSMISSION						
47	350 (Rights)	53,498	65.00		1.16	R5	
48	352	20,963	75.00	10.00	1.19	R4	
49	352 - City Lights Acq	31			5.26		
50	353	616,472	50.00	-10.00	1.53	R1	

Name of Respondent Indiana Michigan Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	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	353 - City Lights Acq	294			5.37		
13	354	222,766	59.00	20.00	1.45	R5	
14	355	109,475	57.00	44.00	2.26	R1	
15	355 - City Lights Acq	69			5.62		
16	356	235,986	65.00	13.00	1.31	R3	
17	356 - City Lights Acq	77			5.27		
18	357	1,594	50.00		1.43	L5	
19	357 - City Lights Acq	733			5.33		
20	358	5,402	60.00	7.00	1.39	R3	
21	358 - City Lights Acq	339			5.31		
22	359	350	65.00		1.49	R5	
23	TOTAL TRANSMISSION	1,268,049					
24							
25	DISTRIBUTION						
26	360 (Rights)	12,320	65.00		1.40	R5	
27	361	8,855	70.00	12.00	1.29	R2	
28	361 - City Lights Acq	312					
29	362	184,096	50.00	1.00	1.70	L0	
30	362 - City Lights Acq	2,433					
31	363	5,488	15.00		6.67		
32	364	221,623	38.00	63.00	3.74	R0.5	
33	364 - City Lights Acq	551					
34	365	306,724	40.00	5.00	1.88	R0.5	
35	365 - City Lights Acq	497					
36	366	62,018	55.00		1.63	R2.5	
37	366 - City Lights Acq	2,218					
38	367	181,875	40.00		2.30	R2	
39	367 - City Lights Acq	1,448					
40	368	267,946	30.00	3.00	2.61	R1.5	
41	368 - City Lights Acq	68					
42	369	147,990	45.00	17.00	2.46	R0.5	
43	369 - City Lights Acq	2,261					
44	370	90,311	25.00	22.00	3.72	S5	
45	370 - City Lights Acq	177					
46	370.16	3,715			10.00		
47	371	21,350	16.00	20.00	7.03	L0	
48	371 - City Lights Acq	9					
49	373	18,600	25.00	7.00	2.47	R0.5	
50	TOTAL DISTRIBUTION	1,542,885					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	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							
13	GENERAL PLANT						
14	390	36,747	45.00	-14.00	1.78	S1.5	
15	391	6,091	22.00	-7.00	3.69	SQ	
16	393	41	14.00		6.05	SQ	
17	394	10,158	16.00		5.64	SQ	
18	395	336	20.00	-1.00	3.70	SQ	
19	396	545	25.00		3.96	SQ	
20	397	26,106	27.00	-14.00	2.60	SQ	
21	397.16	345	10.00		10.00		
22	398	7,983	30.00	-12.00	2.62	SQ	
23	TOTAL GENERAL PLANT	88,352					
24							
25	DEPRECIABLE SUM	6,557,006					
26							
27							
28							
29							
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Schedule Page: 336 Line No.: 7 Column: b

Generation Step-Up Units' (GSUs) depreciation expenses included in I&M's generation formula rates are a subset of transmission depreciation and identified by a query of the plant accounting system.

Schedule Page: 336.3 Line No.: 25 Column: b

The depreciable plant base is the November 30, 2012 total company depreciable plant.

City Light Acq distribution accounts represent the Fort Wayne City Light Acquisition depreciated over 15 years (until February 2025) per agreement filed with the Indiana Utility Regulatory Commission on June 6, 2011 Cause No. 43980.

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Name of Respondent INDIANA MICHIGAN POWER COMPANY - MICHIGAN	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 2012

PARTICULARS CONCERNING CERTAIN INCOME DEDUCTIONS AND INTEREST CHARGES ACCOUNTS

Report the information specified below, in the order given, for the respective income deduction and interest charges accounts. Provide a subheading for each account and a total for the account. Additional columns may be added if deemed appropriate with respect to any account.

(a) *Miscellaneous Amortization* (Account 425) - Describe the nature of items included in this account, the contra account charged, the total of amortization charges for the year, and the period of amortization.

(b) *Miscellaneous Income Deductions* - Report the nature, payee, and amount of other income deductions for the year as required by Accounts 426.1, Donations; 426.2, Life Insurance; 426.3, Penalties; 426.4, Expenditures for Certain Civic, Political and Related Activities; and 426.5. Other Deductions, of the Uniform System of Accounts. Amounts of less than 5% of each account total for the year (or $1,000, whichever is greater) may be grouped by classes within the above accounts

(c) *Interest on Debt to Associated Companies* (Account 430) - For each associated company to which interest on debt was incurred during the year, indicate the amount and interest rate respectively for (a) advances on notes, (b) advances on open account, (c) notes payable, (d) accounts payable, and (e) other debt, and total interest. Explain the nature of other debt on which interest was incurred during the year.

(d) *Other Interest Expense* (Account 431) - Report particulars (details) including the amount and interest rate for other interest charges incurred during the year.

Line No.	Item (a)	Amount (b)
1	425 MISCELLANEOUS AMORTIZATION	
2	TOTAL 425	
3		
4	426 OTHER INCOME DEDUCTIONS	
5		
6	426.1 DONATIONS	
7		
8	Community Chest	764,867
9	Service Organizations	771,514
10	AEP Service Corp Contributions	66,191
11	Schools, Colleges, and Universities	147,371
12	Other minor items	(94,567)
13		
14	Subtotal 426.1	1,655,376
15		
16	426.3 PENALTIES	
17	NERC Penalty with Reliability FIRST Corporation	300,000
18	Other minor items	(1,443)
19		
20		
21	Subtotal 426.3	298,557
22		
23	426.4 EXPENDITURES FOR CERTAIN CIVIC, POLITICAL, AND RELATED ACTIVITY	
24	AEP Service Corp Expenses	734,691
25	Labor Overheads	52,295
26	Edison Electric Institute Dues	72,323
27	Business & Meeting Expenses	84,109
28	Legislative & Lobbying Services	133,879
29	Nuclear Energy Institute	29,358
30	Other Minor Items	(16,450)
31		
32	Subtotal 426.4	1,090,205
33		
34	426.5 OTHER DEDUCTIONS	
35	Factored Customer Accounts Receivable Expense	6,105,913
36	Allowance Losses	10
37	Blackhawk Coal Shutdown Costs	509,232
38	Write off of Investment of Possible SNF Storage	6,365,809
39	AEP Service Corp Expenses	27,324
40	Other minor items	309,812
41		
42	Subtotal 426.5	13,318,100
43		
44	TOTAL 426	16,362,238

Name of Respondent	This Report Is:	Date of Report	Year of Report
INDIANA MICHIGAN POWER COMPANY - MICHIGAN	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 2012

PARTICULARS CONCERNING CERTAIN INCOME DEDUCTIONS AND INTEREST CHARGES ACCOUNTS

Report the information specified below, in the order given, for the respective income deduction and interest charges accounts. Provide a subheading for each account and a total for the account. Additional columns may be added if deemed appropriate with respect to any account.

(a) *Miscellaneous Amortization* (Account 425) - Describe the nature of items included in this account, the contra account charged, the total of amortization charges for the year, and the period of amortization.

(b) *Miscellaneous Income Deductions* - Report the nature, payee, and amount of other income deductions for the year as required by Accounts 426.1, Donations; 426.2, Life Insurance; 426.3, Penalties; 426.4, Expenditures for Certain Civic, Political and Related Activities; and 426.5. Other Deductions, of the Uniform System of Accounts. Amounts of less than 5% of each account total for the year (or $1,000, whichever is greater) may be grouped by classes within the above accounts

(c) *Interest on Debt to Associated Companies* (Account 430) - For each associated company to which interest on debt was incurred during the year, indicate the amount and interest rate respectively for (a) advances on notes, (b) advances on open account, (c) notes payable, (d) accounts payable, and (e) other debt, and total interest. Explain the nature of other debt on which interest was incurred during the year.

(d) *Other Interest Expense* (Account 431) - Report particulars (details) including the amount and interest rate for other interest charges incurred during the year.

Line No.	Item (a)	Amount (b)
1		
2		
3		
4	TOTAL 430	0
5		
6	431 OTHER INTEREST EXPENSE	
7	Interest related to FIN-48 tax adjustments	1,340,517
8	Interest on Customer Deposits	1,782,941
9	Lines of Credit	2,178,131
10	Fuel Recovery	18,617
11	IPP Projects	89,511
12	Fort Wayne Settlement	946,809
13	Other minor items	(138,827)
14		
15		
16	TOTAL 431	6,217,699
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Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2012

EXPENDITURES FOR CERTAIN CIVIC, POLITICAL AND RELATED ACTIVITIES (Account 426.4)

1. Report below all expenditures incurred by the respondent during the year for the purpose of influencing public opinion with respect to the election or appointment of public officials, referenda, legislation or ordinances (either with respect to the possible adoption of new referenda, legislation or ordinances or repeal or modification of existing referenda, legislation or ordinances); approval, modification, or revocation of franchises; or for the purpose of influencing the decisions of public officials which are accounted for as Other Income Deductions, Expenditures for Certain Civic, Political and Related Activities, Account 426.4.
2. Advertising expenditures in this Account shall be classified according to subheadings, as follows: (a) radio, television, and motion picture advertising; (b) newspaper, magazine, and pamphlet advertising; (c) letters or inserts in customer's bills; (d) inserts in reports to stockholders; (e) newspaper and magazine editorial services; and (f) other advertising.
3. Expenditures within the definition of paragraph (1), other than advertising shall be reported according to captions or descriptions clearly indicating the nature and purpose of the activity.
4. If respondent has not incurred any expenditures contemplated by the instruction of Account 426.4, so state.
5. Minor amount may be grouped by classes if the number of items so grouped is shown.

NOTE: The classification of expenses as nonoperating and their inclusion in this amount is for accounting purposes. It does not preclude Commission consideration of proof to the contrary for ratemaking or other purposes.

Line No.	Item (a)	Amount (b)
1	Lobbying Expenses - Company Employees	82,622
2	Lobbying Expenses - Third Party	50,000
3	Misc items under 5% of total (4 items)	3,803
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16	**Total Acct 426.4**	**136,425**
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Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2012

EXTRAORDINARY ITEMS (Accounts 434 and 435)

1. Give below a brief description of each item included in Accounts 434, Extraordinary Income and 435, Extraordinary Deductions.
2. List date of Commission approval for extraordinary treatment of any item which amounts to less than 5% on income. (See General Instruction 7 of the Uniform System of Accounts).
3. Income tax effects relating to each extraordinary item should be listed in Column (c).
4. For additional space use an additional page.

Line No.	Description of Items (a)	Gross Amount (b)	Related Income Taxes (c)
1	Extraordinary Income (Account 434):		
2			
3			
4			
5			
6			
7			
8			
9			
10			
11			
12			
13			
14			
15			
16			
17			
18			
19	Total Extraordinary Income	0	0
20	Extraordinary Deductions (Account 435):		
21			
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33			
34			
35			
36			
37			
38			
39	Total Extraordinary Deductions	0	0
40	Net Extraordinary Items	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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.

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 Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	Nuclear Regulatory Commission				
2	- Inspection Fees	1,835,993	-418,658	1,417,335	
3	- Annual Fees	9,578,500		9,578,500	
4	- Licensing Fees	858,374		858,374	
5					
6					
7	Indiana Rate Case		35,878	35,878	35,878
8	amortz 3/2009-3/2012				
9	per IURC Order #43306				
10					
11	Michigan Rate Case		112,401	112,401	112,401
12	amortz 12/2010-11/2012				
13	per MPSC Rate Case #U-16180				
14					
15	Michigan Rate Case		69,010	69,010	
16	amortz 4/2012-3/2014				
17	per MPSC Rate Case #U-16801				
18					
19	Misc Labor & Incentive accruals		1,722	1,722	
20					
21	Current Indiana Rate Case		851,458	851,458	
22					
23	Current Michigan Rate Case		77,336	77,336	
24					
25	FERC 205 Filing		60,522	60,522	
26					
27	Minor Items < $25,000		22,840	22,840	
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	12,272,867	812,509	13,085,376	148,279

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

REGULATORY COMMISSION EXPENSES (Continued)

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 column (f), (g), and (h) expenses incurred during 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							
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)	Line No.
							1
	928	1,417,335					2
	928	9,578,500					3
	928	858,374					4
							5
							6
				928	35,878		7
							8
							9
							10
				928	112,401		11
							12
							13
							14
			184,068	928	69,010	115,058	15
							16
							17
							18
	928	13,403					19
							20
	928	738,188					21
							22
	928	190,606					23
							24
	928	60,522					25
							26
	928	11,159					27
							28
							29
							30
							31
							32
							33
							34
							35
							36
							37
							38
							39
							40
							41
							42
							43
							44
							45
		12,868,087	184,068		217,289	115,058	46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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 & 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 & 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 & 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 & D Performed Externally:
- (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	A(1)b: Generation: Fossil Fuel Steam	6 items < $50,000
2		1 item <$50,000
3	A(1)e: Generation: Unconventional	1 item <$50,000
4		1 item <$50,000
5	A(2): Transmission	1 item <$50,000
6	A(2): Transmission: Overhead	1 item <$50,000
7	A(3): Distribution	1 item <$50,000
8	A(5): Environment (other than equipment)	Industrial Advisory Committee - Southern Company
9		3 items <$50,000
10	A(6): Other	2 items <$50,000
11		2 items <$50,000
12		3 items <$50,000
13		6 items <$50,000
14	A(6)f: Other: Metering	1 item <$50,000
15	A(7) TOTAL COSTS INCURRED INTERNALLY	
16		
17	B(1): Research Support to Electric Research	EPRI Environmental Science
18		EPRI Research Portfolio
19		EPRI Environmental Controls
20		EPRI Sorbent Activation Process
21		EPRI In-Situ Stabilization of MGP Sediment
22		48 items <$50,000
23		EPRI Nuclear Annual Research
24		1 item <$50,000
25		EPRI Research Portfolio
26		23 items <$50,000
27		10 items <$50,000
28	B(4): Research Support to Others	3 items <$50,000
29		2 items <$50,000
30		
31	B(5) TOTAL COSTS INCURRED EXTERNALLY	
32		
33		
34		
35		
36		
37		
38		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(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 & 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 & 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 & 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 &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.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation (g)	Line No.
		Account (e)	Amount (f)		
38,947		506	38,947		1
2,024		524	2,024		2
9,378		506	9,378		3
3,649		588	3,649		4
7,311		566	7,311		5
29		566	29		6
25		588	25		7
430,207		506	430,207		8
4,586		506	4,586		9
1,976		506	1,976		10
3,506		524	3,506		11
4,722		566	4,722		12
13,273		588	13,273		13
13		588	13		14
519,646			519,646		15
					16
	721,812	506	721,812		17
	226,597	506	226,597		18
	194,920	506	194,920		19
	78,080	506	78,080		20
	56,000	506	56,000		21
	238,098	506	238,098		22
	1,380,290	524	1,380,290		23
	973	524	973		24
	101,103	566	101,103		25
	39,124	566	39,124		26
	92,400	588	92,400		27
	11,626	566	11,626		28
	31,043	588	31,043		29
					30
	3,172,066		3,172,066		31
					32
					33
					34
					35
					36
					37

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	84,948,843		
4	Transmission	1,723,199		
5	Regional Market			
6	Distribution	8,891,776		
7	Customer Accounts	4,021,666		
8	Customer Service and Informational	1,929,995		
9	Sales			
10	Administrative and General	2,787,234		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	104,302,713		
12	Maintenance			
13	Production	44,204,628		
14	Transmission	3,046,978		
15	Regional Market			
16	Distribution	10,178,400		
17	Administrative and General	1,091,441		
18	TOTAL Maintenance (Total of lines 13 thru 17)	58,521,447		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	129,153,471		
21	Transmission (Enter Total of lines 4 and 14)	4,770,177		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	19,070,176		
24	Customer Accounts (Transcribe from line 7)	4,021,666		
25	Customer Service and Informational (Transcribe from line 8)	1,929,995		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	3,878,675		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	162,824,160	7,588,467	170,412,627
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			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

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)	162,824,160	7,588,467	170,412,627
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	29,250,525	1,363,229	30,613,754
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	29,250,525	1,363,229	30,613,754
72	Plant Removal (By Utility Departments)			
73	Electric Plant	5,791,072	269,895	6,060,967
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	5,791,072	269,895	6,060,967
77	Other Accounts (Specify, provide details in footnote):			
78	120 - Nuclr Fuel in Proc of Refinement	252,936		252,936
79	152 - Fuel Stock Undistributed	5,779,461		5,779,461
80	163 - Stores Expense Undistributed	6,713,489	-6,713,489	
81	165 - Other Prepayments	92,637		92,637
82	183 - Prelim Survey	71,874	-71,874	
83	184 - Clearing Accounts	2,436,228	-2,436,228	
84	185 - ODD Temporary Facilities	55,138		55,138
85	186 - Misc Deferred Debits	2,168,053		2,168,053
86	188 - Research & Development	-2,341		-2,341
87	228 RAD Waste Accrual	37,336		37,336
88	417 Misc Exp	20,970,192		20,970,192
89	426 - Political Activities	88,318		88,318
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	38,663,321	-9,221,591	29,441,730
96	TOTAL SALARIES AND WAGES	236,529,078		236,529,078

Schedule Page: 354 Line No.: 28 Column: b

The labor charges from AEP Service Corporation included in the development of the I&M generation formula rate payroll allocator is derived from a query of the general ledger.

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2012

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 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 utillity plant classification and reference to order of the Commission or other authorization.

NONE

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2012

CHARGES FOR OUTSIDE PROFESSIONAL AND OTHER CONSULTATIVE SERVICES

1. Report the information specified below for all charges made during the year included in any account (including plant accounts) for outside consultative and other professional services. (These services include rate, management, construction, engineering research, financial, valuation, legal, accounting, purchasing, advertising, labor relations, and public relations, rendered the respondent under written or oral arrangement, for which aggregate payments were made during the year to any corporation, partnership, organization of any kind, or individual (other than for services as an employee or for payments made for medical and related services) amounting to more than $50,000, including payments for legislative services, except those which should be reported in Account 426.4, Expenditures for Certain Civic, Political and Related Activities.)

(a) Name and address of person or organization rendering services,

(b) description of services received during year and project or case to which services relate,

(c) basis of charges,

(d) total charges for the year, detailing utility department and account charged.

2. For any services which are of a continuing nature, give the date and term of contract and date of Commission authorization, if contract received Commission approval.

3. Designate with an asterisk associated companies.

1 a. American Electric Power Service Corporation - * (Associated Company)
1 Riverside Plaza
Columbus, Ohio 43215-2373

b. American Electric Power Service Corporation renders management and advisory services to American Electric Power Company, Inc. (Parent) and its subsidiary companies. Such services furnished include, but are not limited to: administrative, planning & engineering, financial and accounting management, legal, fuel & material procurement, pension & employee benefits administration, and other technical services.

c. The services are provided on a non-profit basis. Under a work order system, costs are identified and billed directly to the company benefiting from the service rendered to the extent practical. Other costs that cannot be directly attributed to particular companies are collected on work orders which are allocated to the companies based on the appropriate factor.

2. Date of Contract - June 15,2000 (supercedes contract dated January 1, 1980)
Term of Contract - Indeterminate
AEPSC activities are authorized by the FERC under the Public Utility Holding Company Act of 2005
Date of SEC Authorization - June 14, 2000

Total charges for the year and Utility Department and account charged

			ACCOUNT	AMOUNT
Electric	Construction Work in Progress		107	28,859,638
	Retirement Work in Progress		108	186,828
	Nonutility Property		121	11,965
	Fuel Stock		151	9
	Fuel Stock Undistributed		152	2,905,518
	Clearing Accounts		163	1,329,358
	Regulatory Assets		182.3	146
	Preliminary Survey & Investig. Charges		183	287,374
	Clearing Accounts		184	57,981
	Misc Deferred Debits		186	414,142
	Deferred Debits-R&D		188	3,652,301
	Current & Accrued Liabilities		242	123
	Depreciation		403	9,163
	Non-Utility Operations Revenue		417	1,195,054
	Misc Non-Operating Revenues		421	1
	Other Income Deductions		426	841,907
Electric	Account 401	Operating Expense	500	5,154,408
			501	130,669
			502	202,784
			505	0
			506	831,180
			517	36,470
			520	20
			524	1,094,548
			535	611,929
			537	227
			538	0
			539	730,860
			546	39,699
			547	64
			548	(15)
			549	2
			555	166,942
			556	1,619,611
			557	4,796,553
			560	2,008,033
			561	1,516,913

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2012

Electric	Account 401	Operating Expense (contd.)	562	8,441
			563	12,907
			566	1,006,678
			567	716
			580	1,099,603
			581	6,666
			582	18,926
			583	53
			584	18,440
			586	259,942
			588	2,122,410
			589	(2)
			901	167,512
			902	131,531
			903	12,462,307
			904	2,402
			905	30,978
			907	273,058
			908	121,413
			909	-
			910	599
			911	(18)
			912	7
			920	21,446,387
			921	1,353,861
			923	19,830,330
			924	19,502
			925	39,924
			926	159,730
			928	88,719
			930	599,293
			931	14,998
Electric	Account 401	Total Operating Expense		80,238,213
Electric	Account 402	Maintenance Expense	510	687,500
			511	58,505
			512	926,220
			513	654,434
			514	56,737
			528	245,214
			530	770,270
			531	63,313
			532	7,108
			541	12,811
			542	37,117
			543	45,678
			544	33,295
			545	2,752
			553	(19)
			568	85,865
			569	615,677
			570	257,031
			571	269,790
			572	(6)
			590	10,067
			591	10,227
			592	122,167
			593	143,209
			594	149
			595	41
			597	1,103
			935	42,842
Electric	Account 402	Total Maintenance Expense		5,159,098
		Total O&M		85,397,311
		Total AEP Service Corp charges		$ 125,148,820

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NAME / ADDRESS	DESCRIPTION	CHARGES	ACCOUNT	AMOUNT
ABB INC 200 LAKE ROAD BELTON, TX 76513	electronic equipment services	Invoice Cost	107	55,222
ACRT INC 1333 HONE AVENUE AKRON, OH 43310	environmental consulting services	Invoice Cost	107, 593	160,207
ADM ASSOCIATES INC 3239 RAMOS CIRCLE SACRAMENTO, CA 95827	environmental consulting services	Invoice Cost	908	134,211
ADVANCED INDUSTRIAL MACHINING 30 DILLMONT DRIVE #286 WORTHINGTON, OH 43235	nuclear plant equipment rental	Invoice Cost	107	86,106
AERIAL SOLUTIONS INC 7074 RAMSEY FORD ROAD TABOR CITY, NC 28463	tree trimming services	Invoice Cost	571, 593	79,935
AEROTEK INC 7301 PARKWAY DRIVE HANOVER, MD 21076	equipment & maintenance services	Invoice Cost	107, 108, 186, 511, 595	143,361
ALL CITIES OCCUPATIONAL & ENV 3333 S. STATE STREET SAINT JOSEPH, MI 49085	nuclear plant support staffing	Invoice Cost	524	61,898
ALSTOM POWER INC 2800 WATERFORD LAKE DR MIDLOTHIAN, VA 23112	inspection & measurement services	Invoice Cost	107, 513	9,573,827
AREA WIDE PROTECTIVE 826 OVERHOLT ROAD KENT, OH 44240	traffic control services	Invoice Cost	107, 108, 186, 571, 583 588, 593, 594, 596	1,120,841
ASHER AGENCY INC 535 W. WAYNE STREET FORT WAYNE, IN 46801	marketing services	Invoice Cost	908, 923	142,977
ASPLUNDH CONSTRUCTION CORP 950 TAYLOR STATION ROAD. COLUMBUS, OH 43230	construction contracting services	Invoice Cost	107, 108, 185, 186, 571 584, 588, 593, 594, 596 930	31,133,276
ATC ENGINEERING SERVICES OF OHIO 11121 CANAL ROAD CINCINNATI, OH 45241	fly ash landfill engineering services	Invoice Cost	107	195,746
B & S AIR INC 416 BROAD STREET LUMPKIN, GA 31815	reforestation services	Invoice Cost	571	73,495
BABCOCK & WILCOX CO 20 S. VAN BUREN DRIVE BARBERTON, OH 44203	plant equipment repair services	Invoice Cost	107	50,500
BARTLETT NUCLEAR INC 7633 EAST 63RD PLACE #400 TULSA, OK 74133	nuclear engineering services	Invoice Cost	530	57,645
BJ PROCESS & PIPELINE SVCS 414 PINCKNEY HOUSTON, TX 77249	boiler cleaning services	Invoice Cost	107	165,479
BOSE PUBLIC AFFAIRS 1600 FIRST INDIANA PLAZA INDIANAPOLIS, IN 46204	legislative services	Invoice Cost	426, 921	59,990

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NAME / ADDRESS	DESCRIPTION	CHARGES	ACCOUNT	AMOUNT
BRENNAN, J F CO INC 820 BAINBRIDGE STREET LA CROSSE, WI 54603	construction contracting services	Invoice Cost	107, 108, 543	835,794
BROWN ELECTRIC CO INC 1100 CHARLES AVE DUNBAR, WV 25064	electrical construction services	Invoice Cost	107	237,710
BURNS & MCDONNELL 9400 WARD PARKWAY KANSAS CITY, MO 64114	engineering & consulting services	Invoice Cost	107	67,240
CENTRIFUGAL TECHNOLOGY INC 330 CENTECH DRIVE HICKORY, KY 42051	equipment parts & services	Invoice Cost	514	76,955
CFM/VR TESCO INC 1875 FOX LANE ELGIN, IL 60123	valve repairs	Invoice Cost	512	87,258
CMI SERVICES INC 18 EAST JEFFERSON STREET FRANKLIN, IN 46131	engineering & management services	Invoice Cost	107, 108, 586, 588	1,790,005
COMMONWEALTH ASSOCIATES INC 2700 W ARGYLE JACKSON, MI 49204	electrical engineering & design services	Invoice Cost	107	371,285
CULY CONSTRUCTION 5 INDUSTRIAL PARK DRIVE WINCHESTERM IN 47394	drainage construction services	Invoice Cost	107, 108, 570, 592	999,992
CUSTOM MECHANICAL CONSTRUCTION 1609 ALLENS LANE EVANSVILLE, IL 47710	construction contracting services	Invoice Cost	107, 108, 511, 512	100,015
DAI MANAGEMENT CONSULTANTS INC 1370 WASHINGTON PIKE #103 BRIDGEVILLE, PA 15017	management consulting services	Invoice Cost	506	76,079
DAVEY RESOURCE GROUP 3728 FISHCREEK ROAD STOW, OH 44224	tree trimming services	Invoice Cost	107, 571	217,059
DAY & ZIMMERMAN NPS INC 1827 FREEDOM RD LANCASTER, PA 17601	nuclear engineering support	Invoice Cost	107, 108, 163, 228, 512 520, 524, 528, 529, 530 531, 532	17,309,146
DEVELOPMENT COUNSELLORS INTERNAT'L 215 PARK AVENUE SOUTH, 10TH FLOOR NEW YORK, NY 10003	marketing services	Invoice Cost	912	209,777
DISCOVER READY LLC 1 EXCHANGE PLAZA FLOOR 6 NEW YORK, NY 10006	business consulting services	Invoice Cost	524	58,546
E & T TREE SERVICE 125 MT AUBURN ST DUNKIRK, IN 47336	landscaping & tree removal services	Invoice Cost	107, 184, 562, 571, 582	58,033
EASI LLC 1551 EAST LINCOLN AVENUE #105 MADISON HEIGHTS, MI 48071	employment services	Invoice Cost	107, 108, 186, 560, 935	836,295
EDISON ELECTRIC INSTITUTE 605 MELROSE STREET ALEXANDRIA, VA 22302	trade organization fees	Invoice Cost	506	83,852

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NAME / ADDRESS	DESCRIPTION	CHARGES	ACCOUNT	AMOUNT
EDKO LLC 908 S. 11TH STREET BROKEN ARROW, OK 74012	perimeter security services	Invoice Cost	107, 593	1,157,230
EMERGENCY RADIO SERVICE INC 4410 EARTH DR FORT WAYNE, IN 46809	radio tower repairs & inspection	Invoice Cost	107	52,625
ENERFAB INC 4955 SPRING GROVE CINCINNATI, OH 45232	fabrication & installation services	Invoice Cost	107, 935	72,583
ENGART AMERICA INC 150 STANAFORD RD BECKLEY, WV 25802	plant equipment maintenance	Invoice Cost	107, 512	231,067
ENGINEERING VISION INC 5812 INDUSTRIAL ROAD FORT WAYNE, IN 46825	engineering & surveying services	Invoice Cost	107, 186, 571	197,978
ENVIRONMENTAL REMEDIATION SVCS. 4010 OPTION PASS FT WAYNE, IN 46818	emergency cleanup services	Invoice Cost	107, 186, 580, 588, 594 935	113,044
EXPONENT INC 1800 DIAGONAL ROAD #500 ALEXANDRIA, VA 22314	engineering services	Invoice Cost	524	168,463
FINANCIAL CONCEPTS & APPLICATIONS 3907 RED RIVER AUSTIN, TX 78751	financial consulting firm	Invoice Cost	186, 921	85,925
FLSMIDTH AIRTECH INC 13100 EAST 101ST STREET NORTH OWASSO, OK 74055	material handling system project	Invoice Cost	107, 183	2,774,708
FUGRO AERIAL & MOBILE MAPPING INC 5615 CORPORATE BLVD., STE 4 BATON ROUGE, LA 70808	aerial photogrammetric services	Invoice Cost	107	167,389
G & L CORPORATION 3101 BROOKLYN AVE FORT WAYNE, IN 46809	equipment moving services	Invoice Cost	107, 108, 186, 570, 592	220,644
G4S SECURE SOLUTIONS (USA) INC 4200 WACKENHUT DR PALM BEACH GARDENS, FL 33410	security services	Invoice Cost	107, 108, 184, 506	289,115
GAYLOR INC 5750 CASTLE CREEK PKWY N DRIVE INDIANAPOLIS, IN 46250	electrical contracting services	Invoice Cost	107, 108	215,121
GOOD CENTS 10350 BLUEGRASS PARKWAY LOUISVILLE, KY 40299	marketing & technology solutions	Invoice Cost	908	5,271,305
GRAYLOC PRODUCTS 11835 CHARLES ROAD HOUSTON, TX 77041	valves & pipe fitting services	Invoice Cost	513	81,160
GUS COMMERCIAL DIVERS LLC 12839 INDUSTRIAL PARK DR. GRANGER, IN 46530	underwater construction services	Invoice Cost	542, 543	289,184
H C NUTTING 611 LUNKEN PARK DR CINCINNATI, OH 45226	concrete testing services	Invoice Cost	107, 186	243,582

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Charges for Outside Professional & Other Consulting Services - Payments of $25,000 or more (contd.)

NAME / ADDRESS	DESCRIPTION	CHARGES	ACCOUNT	AMOUNT
HAVERFIELD INTERNATIONAL INC 1750 EMMITSBURG ROAD GETTYBURG, PA 17325	aerial inventory inspections	Invoice Cost	571, 930	227,553
HELICOPTER MINIT-MEN INC 3136 TRABUE ROAD COLUMBUS, OH 43204	helicopter services	Invoice Cost	107, 571	334,448
HENRY, ROBERT CORP 404 S. FRANCIS STREET SOUTH BEND, IN 46617	drain installation	Invoice Cost	107, 108, 186, 584, 588 593, 594, 596	1,145,391
HERMAN & GOETZ INC 2915 N HOME STREET MISHAWAKA, IN 46545	electrical construction services	Invoice Cost	542	53,625
HONEYWELL INTERNATIONAL INC 101 COLUMBIA ROAD MORRISTOWN, NJ 07962	industrial & security system supplies	Invoice Cost	908	607,287
HOOSIER HELICOPTER SERVICES 7900 N. THAMES DRIVE BLOOMINGTON, IN 47408	helicopter services	Invoice Cost	563, 571	145,552
HUNTON & WILLIAMS 200 PENNSYLVANIA AVENUE, NW WASHINGTON, DC 20037	trade organization fees	Invoice Cost	506	93,654
INDUSTRIAL CONTRACTORS INC 1001 BUCHANAN ROAD EVANSVILLE, IN 47720	equipment repairs	Invoice Cost	107, 108, 152, 186, 500 501, 506, 510, 511, 512 513, 514	9,311,463
INSERV INC 1604 RUPEL ST SOUTH BEND, IN 46628	building maintenance services	Invoice Cost	107, 108, 186, 588, 593	84,495
JACO ENVIRONMENTAL INC various US locations	recycling services	Invoice Cost	908	364,810
JOINT FIELD SERVICES INC 1020 BROADWAY ST MARSEILLES, IL 61341	nuclear plant support services	Invoice Cost	107, 530	105,812
KATTEN MUCHIN ROSENMAN LLP 525 WEST MONROE STREET CHICAGO, IL 60661	business consulting services	Invoice Cost	506	91,987
KEITH FIRE EXTINGUISHER SERVICE 601 S HIGH ST RISING SUN, IN 47040	fire extinguisher inspection	Invoice Cost	514	124,625
KEMNA SERVICES INC P O BOX 1043 INDIANAPOLIS, IN 46071	office building repairs	Invoice Cost	908	649,613
KENRICH GROUP LLC 1250 CONNECTICUT AVE NW WASHINGTON, DC 20036	legal services (liability claims)	Invoice Cost	923	193,699
KENT POWER INC 90 SPRING STREET KENT CITY, MI 49330	power line relocation	Invoice Cost	107, 108, 186, 571	921,406
KNIGHT COST ENGINEERING SERVICES 22 MOUNTAIN VIEW TERRACE NEW MILFORD, CT 06776	engineering services	Invoice Cost	923	80,100

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Charges for Outside Professional & Other Consulting Services - Payments of $25,000 or more (contd.)

NAME / ADDRESS	DESCRIPTION	CHARGES	ACCOUNT	AMOUNT
KWEST GROUP LLC 1180 S PLASTERBED ROAD PORT CLINTON, OH 43452	excavation & site preparation	Invoice Cost	107	75,177
LANDSCAPE SOLUTIONS GROUP INC 52041 PATRICIA LANE SOUTH BEND, IN 46628	landscaping services	Invoice Cost	107, 108, 184, 186, 563 563, 588, 594	68,288
LAPORTE CONSTRUCTION 512 H STREET LAPORTE, IN 46352	excavation & site preparation	Invoice Cost	107, 108, 543	250,293
LE MYERS COMPANY 2415 W THOMPSON ROAD INDIANAPOLIS, IN 46217	electrical contracting services	Invoice Cost	107, 108, 186	867,311
LOCKHEED MARTIN UTILITY SERVICES INC various US locations	engineering services	Invoice Cost	908	133,205
MANPOWER various US locations	temporary staffing services	Invoice Cost	107, 108, 570, 580, 584 595, 930	234,564
MARTIN ENGINEERING CO 3223 SOUTH MEADOWBROOK ROAD SPRINGFIELD, IL 62711	engineering services	Invoice Cost	512	51,329
MEAD & WHITE ELECTRIC INC 9895 RED ARROW HIGHWAY BRIDGMAN, MI 49106	electrical construction services	Invoice Cost	107, 542, 543	133,048
MICHIANA LAND SERVICES INC 505 PLEASANT ST ST JOSEPH, MI 49085	land right of way services	Invoice Cost	107, 108, 186, 563, 571 930	1,010,003
MICHIGAN COMMUNITY ACTION AGENCY 2173 COMMONS PARKWAY OKEMOS, MI 48864	energy optimization project	Invoice Cost	908	4,420,319
MOFFITT REHAB SERVICES INC 200 PARK ROAD HAWESVILLE, KY 42348	excavation & site preparation	Invoice Cost	107, 152, 501	1,074,025
MPW ENVIRONMENTAL SERVICES 9711 LANCASTER RD SE HEBRON, OH 43025	plant equipment maintenance & cleaning	Invoice Cost	107, 108, 152, 501, 511 512, 513	632,825
NAVIGANT CONSULTING INC 110 E. WAYNE STREET FORT WAYNE, IN 46802	management consulting services	Invoice Cost	908	76,353
NELSON TREE SERVICE INC 3300 OFFICE PARK DRIVE DAYTON, OH 45439	tree trimming services	Invoice Cost	107, 186, 571	1,098,246
NESCO SALES & RENTALS 4121 SOLUTIONS CENTER CHICAGO. IL 60677	plant equipment maintenance	Invoice Cost	107, 108, 563, 571, 930	160,422
NEW RIVER ELECTRICAL CORP 15 CLOVERDALE PLACE CLOVERDALE, VA 24077	storm restoration services	Invoice Cost	107, 108	578,111
NEWKIRK ELECTRIC ASSOCIATES 1875 ROBERTS STREET MUSKEGON, MI 49442	electrical construction services	Invoice Cost	107, 108, 571	2,443,404
OPOWER INC 1515 N COURTHOUSE RD ARLINGTON, VA 22201	industrial supply services	Invoice Cost	908	464,885

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Charges for Outside Professional & Other Consulting Services - Payments of $25,000 or more (contd.)

NAME / ADDRESS	DESCRIPTION	CHARGES	ACCOUNT	AMOUNT
OTIS ELEVATOR COMPANY 622 E MARKET ST INDIANAPOLIS, IN 46202	elevator repair & inspection services	Invoice Cost	511, 935	132,273
PARKLINE INC 4224 SCOTTSDALE ROAD ST JOESEPH, MI 49085	prefabricated metal building	Invoice Cost	107	274,602
PARKS DRILLING CO 5745 AVERY ROAD DUBLIN, OH 43016	drilling services	Invoice Cost	107	605,032
PERRY BALLARD INC 526 UPTON DR E ST JOSEPH, MI 49085	nuclear plant PR & media support services	Invoice Cost	921, 923	99,150
POOLED EQUIPMENT INVENTORY CO 3988 LORNA ROAD BIRMINGHAM. AL 35202	electrical equipment sales	Invoice Cost	163	125,400
POWER SECURE INC 1609 HERTIAGE COMMERCE CT. WAKE FOREST, NC 27587	industrial machinery & equipment services	Invoice Cost	593	89,545
PUBLIC UTILITIES MAINTENANCE 99TH AVENUE QUEENS VILLAGE, NY 11429	electric tower painting	Invoice Cost	571	139,413
PULVERIZER SERVICES, INC 200 PARK LOOP CALHOUN, KY 42327	plant equipment rebuilding services	Invoice Cost	107, 108, 512	353,002
REMA TIP TOP NORTH AMERICA INC 119 ROCKLAND AVENUE NORTHVALE, NJ 07647	chemical & allied product services	Invoice Cost	107, 108, 512	68,643
REYNOLDS INC 25866 NETWORK PLACE CHICAGO, IL 60673	water system services	Invoice Cost	107	113,454
RILEY POWER INC 5 NEPONSET STREET WORCESTER, MA 01606	electrical services	Invoice Cost	107	3,461,395
SAFWAY SERVICES LLC 3200 SHEFFIELD AVE HAMMOND, IN 46327	equipment rental	Invoice Cost	107, 529, 530, 531, 532	313,932
SARGENT & LUNDY LLC 55 E MONROE ST CHICAGO, IL 60603	nuclear engineering services	Invoice Cost	107, 186	274,779
SCEPTRE MECHANICAL INC 93 E COUNTY ROAD 200 N ROCKPORT, IN 47635	industrial supply services	Invoice Cost	152, 501, 506	1,222,286
SCHWEITZER ENGINEERING LABORATORY 2350 NE HOPKINS COURT PULLMAN, WA 99163	engineering services	Invoice Cost	107	81,984
SCIENTECH various US locations	software support & licensing services	Invoice Cost	107, 108	755,629
SERVICE ELECTRIC COMPANY 1631 EAST 25TH STREET CHATTANOOGA, TN 37404	electronic equipment services	Invoice Cost	107	716,624

Charges for Outside Professional & Other Consulting Services - Payments of $25,000 or more (contd.)

NAME / ADDRESS	DESCRIPTION	CHARGES	ACCOUNT	AMOUNT
SHAW CONSULTANTS INTL. 1 MAIN STREET #900 CAMBRIDGE, MA 02142	appraisal consulting services	Invoice Cost	186	69,927
SLATILE ROOFING & RESTORATION 1703 SOUTH IRONWOOD SOUTH BEND, IN 46613	roofing installation & repairs	Invoice Cost	542	82,372
SPECIALTY SYSTEMS OF SOUTH BEND INC 55215 MAYFLOWER ROAD SOUTH BEND, IN 46628	asbestoes removal services	Invoice Cost	107, 108, 186	69,449
SSOE INC 100 EAST CAMPUS VIEW BLVD, STE. 340 COLUMBUS, OH 43235	engineering services	Invoice Cost	107, 108, 500	60,306
SUN TECHNICAL SERVICES INC 6490 S MCCARRAN BLVD RENO, NV 89509	engineering services	Invoice Cost	107, 108, 163, 165, 183 500, 501, 506, 512, 517 520, 524, 529, 530, 532	1,422,514
T&A TRUCKING 2754 PINE DRIVE NE NEW PHILADELPHIA, OH 44663	trucking services	Invoice Cost	107, 163, 593, 930	171,871
TECMARKET WORKS 165 WEST NETHERWOOD ROAD OREGON, WI 53575	management consulting services	Invoice Cost	908	187,629
TEMPORARY TECHNICAL SERVICES 915 AIRPORT RD JACKSON, MI 49202	temporary staffing services	Invoice Cost	107, 108, 186, 580, 583 588, 593	305,623
TOLEDO CAISSON CORPORATION 6275 CONSEAR ROAD OTTAWA LAKE, MI 49267	construction contracting services	Invoice Cost	107	809,454
UC SYNERGETIC INC 3440 LAKEMONT BLVD FORT MILL, SC 29708	plant engineering support	Invoice Cost	107, 108, 186, 580, 588 590, 593	328,335
UNDERWATER CONSTRUCTION CORP 110 PLAINS RD ESSEX, CT 06426	underwater construction services	Invoice Cost	107, 108, 513, 542, 543	102,808
UNITED CONSTRUCTION CO INC 1340 OLD ROSEMAR ROAD PARKERSBURG, WV 26104	construction contracting services	Invoice Cost	107, 108, 183, 529	433,916
UTILITY LOCATORS various US locations	power line construction services	Invoice Cost	107, 584	1,356,727
UTTER CONSTRUCTION INC 1302 STATE ROUTE 133 BETHEL, OH 45106	fly ash pond construction services	Invoice Cost	107, 186, 501	2,524,950
VARO ENGINEERS INC 2751 TULLER PARKWAY, SUITE 100 DUBLIN, OH 43017	engineering services	Invoice Cost	107	63,127
VAUGHN INDUSTRIES 1201 E. FINDLAY STREET CAREY, OH 43316	substation electrical work services	Invoice Cost	107, 108, 570	2,448,508
WB-KOESTER CONSTRUCTION LLC 14601 HIGHWAY 41 NORTH, SUITE 200 EVANSVILLE, IN 47725	fly ash landfill construction services	Invoice Cost	107, 186	64,675

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Charges for Outside Professional & Other Consulting Services - Payments of $25,000 or more (contd.)

NAME / ADDRESS	DESCRIPTION	CHARGES	ACCOUNT	AMOUNT
WESTINGHOUSE ELECTRIC CO 4350 NORTHERN PIKE MONROEVILLE, PA 15146	nuclear support services	Invoice Cost	530	863,085
WHAYNE SUPPLY CO 1400 CECIL AVENUE LOUISVILLE, KY 40211	equipment repair services	Invoice Cost	107, 108, 152, 501, 512 514	681,024
WIGHTMAN & ASSOCIATES, INC 110 E. WAYNE STREET FORT WAYNE, IN 46801	topographic surveying services	Invoice Cost	107, 186	437,141
WILLIAMS CREEK MANAGEMENT CORP 4620 S. COUNTY ROAD 600 EAST PLAINFIELD, IN 46168	stream bank stabilization project services	Invoice Cost	107, 571	332,491
WISCONSIN ENERGY CONSERVATION 431 CHARMWAY DRIVE MADISON, WI 53719	business consulting services	Invoice Cost	908	287,143
WORLEYPARSONS GROUP INC 2675 MORGANTOWN ROAD READING, PA 19607	engineering services	Invoice Cost	107, 183	15,956,413
WRIGHT TREE SERVICE INC 139 6TH STREET DESMOINES, IA 50306	tree trimming services	Invoice Cost	107, 571	3,550,963
ZIOLKOWSKI CONSTRUCTION INC 4050 RALPH JONES DRIVE SOUTH BEND, IN 46628	transformer painting services	Invoice Cost	108, 935	81,181

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)	18,403,788
3	Steam	12,206,909			
4	Nuclear	17,721,798	23	Requirements Sales for Resale (See instruction 4, page 311.)	5,036,929
5	Hydro-Conventional	87,364			
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	17,958,337
7	Other				
8	Less Energy for Pumping		25	Energy Furnished Without Charge	42
9	Net Generation (Enter Total of lines 3 through 8)	30,016,071	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
10	Purchases	13,483,639	27	Total Energy Losses	2,100,614
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	43,499,710
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received				
17	Delivered				
18	Net Transmission for Other (Line 16 minus line 17)				
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	43,499,710			

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).

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	4,174,318	1,926,687	3,686	20	800
30	February	3,737,544	1,737,672	3,515	13	800
31	March	2,890,512	917,628	3,392	5	800
32	April	2,718,177	857,119	3,195	11	700
33	May	3,011,603	966,202	3,762	29	1600
34	June	3,556,205	1,378,174	4,576	28	1600
35	July	4,199,203	1,662,805	4,726	6	1300
36	August	4,015,552	1,762,793	4,488	3	1600
37	September	3,708,879	1,805,668	4,044	4	1500
38	October	3,841,091	1,887,395	3,255	31	1200
39	November	3,591,334	1,604,993	3,427	28	0800
40	December	4,055,292	2,015,990	3,525	11	2000
41	TOTAL	43,499,710	18,523,126			

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Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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 Mct. 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.

Line No.	Item (a)	Plant Name: *ROCKPORT UNIT 1 I&M* (b)			Plant Name: *ROCKPORT UNIT 2 I&M* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam			Steam		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional			Conventional		
3	Year Originally Constructed	1984			1989		
4	Year Last Unit was Installed	1984			1989		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	660.00			650.00		
6	Net Peak Demand on Plant - MW (60 minutes)	704			677		
7	Plant Hours Connected to Load	7912			7915		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	660			650		
10	When Limited by Condenser Water	658			650		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	4803537000			4586254000		
13	Cost of Plant: Land and Land Rights	6508470			68095		
14	Structures and Improvements	90933441			6107966		
15	Equipment Costs	563441785			90871528		
16	Asset Retirement Costs	1382784			1261849		
17	Total Cost	662266480			98309438		
18	Cost per KW of Installed Capacity (line 17/5) Including	1003.4341			151.2453		
19	Production Expenses: Oper, Supv, & Engr	1563524			1584079		
20	Fuel	102867580			100716513		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	3003198			2781607		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	750960			712626		
26	Misc Steam (or Nuclear) Power Expenses	4360876			4604294		
27	Rents	2371			70149622		
28	Allowances	6658372			6658372		
29	Maintenance Supervision and Engineering	955876			980463		
30	Maintenance of Structures	587605			183701		
31	Maintenance of Boiler (or reactor) Plant	4081310			3947034		
32	Maintenance of Electric Plant	1090121			1028390		
33	Maintenance of Misc Steam (or Nuclear) Plant	616008			369094		
34	Total Production Expenses	126537801			193715795		
35	Expenses per Net KWh	0.0263			0.0422		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. 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.

Plant Name: *ROCKPORT TOTAL I&M* (d)			Plant Name: *ROCKPORT TOTAL PLANT* (e)			Plant Name: *TANNERS CREEK PLANT* (f)			Line No.
		Steam			Steam			Steam	1
		Conventional			Conventional			Conventional	2
		1984			1984			1951	3
		1989			1989			1964	4
		1310.00			2620.00			995.00	5
		1320			2640			970	6
		7915			7915			6875	7
		0			0			0	8
		1310			2620			995	9
		1308			2615			985	10
		0			232			120	11
		9389791000			18779568000			2817118000	12
		6576565			13123804			4099388	13
		97041407			195928472			53621818	14
		654313313			1310544154			578663459	15
		2644633			5220652			23223153	16
		760575918			1524817082			659607818	17
		580.5923			581.9913			662.9224	18
		3147604			5677295			2680937	19
		203584092			407732189			82806214	20
		0			0			0	21
		5784804			11619922			3800436	22
		0			0			0	23
		0			0			0	24
		1463585			2927183			108401	25
		8965171			12522815			7829927	26
		70151994			138439754			3630	27
		13316743			13316743			4216741	28
		1936338			3799782			1774201	29
		771306			1542462			1349791	30
		8028344			16011567			7775749	31
		2118511			4237886			1735486	32
		985101			1970253			894839	33
		320253593			619797851			114976352	34
		0.0341			0.0330			0.0408	35
Coal	Oil		Coal	Oil		Coal	Oil		36
Tons	Barrels		Tons	Barrels		Tons	Barrels		37
5138522	14663	0	10277026	29326	0	1500310	11973	0	38
8952	136989	0	8952	136989	0	10172	137315	0	39
39.174	131.716	0.000	39.174	131.716	0.000	54.715	129.488	0.000	40
39.254	127.816	0.000	39.309	127.816	0.000	54.170	128.562	0.000	41
2.192	22.215	0.000	2.196	22.215	0.000	2.663	22.292	0.000	42
0.022	0.000	0.000	0.022	0.000	0.000	0.028	0.000	0.000	43
9806.000	0.000	0.000	9806.000	0.000	0.000	10859.000	0.000	0.000	44

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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 Mct. 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.

Line No.	Item (a)	Plant Name: *DONALD C COOK PLANT* (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Nuclear					
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional					
3	Year Originally Constructed	1975					
4	Year Last Unit was Installed	1978					
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	2285.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	2298			0		
7	Plant Hours Connected to Load	8784			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	2191			0		
10	When Limited by Condenser Water	2059			0		
11	Average Number of Employees	1065			0		
12	Net Generation, Exclusive of Plant Use - KWh	17721798000			0		
13	Cost of Plant: Land and Land Rights	1879588			0		
14	Structures and Improvements	326729132			0		
15	Equipment Costs	1960453225			0		
16	Asset Retirement Costs	277556034			0		
17	Total Cost	2566617979			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	1123.2464			0		
19	Production Expenses: Oper, Supv, & Engr	16871908			0		
20	Fuel	159132153			0		
21	Coolants and Water (Nuclear Plants Only)	5310279			0		
22	Steam Expenses	9761288			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	2212556			0		
26	Misc Steam (or Nuclear) Power Expenses	86687373			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	12052240			0		
30	Maintenance of Structures	2520038			0		
31	Maintenance of Boiler (or reactor) Plant	62576972			0		
32	Maintenance of Electric Plant	2805327			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	18320310			0		
34	Total Production Expenses	378250444			0		
35	Expenses per Net KWh	0.0213			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Nuclear					
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.839	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.009	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	10700.000	0.000	0.000	0.000	0.000	0.000

Schedule Page: 402 Line No.: -1 Column: e

The Rockport Plant is a two unit coal fired generating facility. Unit 1 is jointly owned and Unit 2 is jointly leased 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 and leased by Respondent and AEP Generating Company.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	Hydroelectric					
2	Berrien Springs	1908	7.20	9.0	29,705	15,008,625
3	Buchanan (Project #2551)	1919	4.10	4.0	13,675	7,318,280
4	Constantine (Project #10661)	1921	1.20	2.0	4,909	2,751,395
5	Elkhart (Project #2651)	1913	3.44	3.0	12,891	6,390,818
6	Mottville (Project #401)	1923	1.68	2.0	4,411	4,164,775
7	Twin Branch (Project #2579)	1904	4.80	5.0	21,773	11,898,076
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GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 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.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
2,084,531	428,845		234,791			2
1,784,946	320,995		394,488			3
2,292,829	111,731		116,896			4
1,857,796	267,305		439,793			5
2,479,033	183,402		321,501			6
2,478,766	399,713		153,263			7
						8
						9
						10
						11
						12
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Name of Respondent INDIANA MICHIGAN POWER COMPANY MICHIGAN	This Report is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo,Da,Yr)	Year of Report December 31, 2012

CHANGES MADE OR SCHEDULED TO BE MADE IN GENERATING PLANT CAPACITIES

Give below information called for concerning changes in electric generating plant capacities during the year.

A. Generating Plants or Units Dismantled, Removed from Service, Sold or Leased to Others During Year.

1. State in column (b) whether dismantled, removed from service, sold, or leased to another. Plants removed from service include those not maintained for regular or emergency service.
2. In column (f), give date dismantled, removed from service, sold, or leased to another. Designate complete plants as such.

Line No.	Name of Plant (a)	Disposition (b)	Installed Capacity (in megawatts) Hydro (c)	Steam (d)	(Other) (e)	Date (f)	If Sold or Leased to Another, Give Name and Address of Purchaser or Lessee (g)
1	NONE						
2							
3							
4							
5							
6							
7							

B. Generating Units Scheduled for or Undergoing Major Modifications

Line No.	Name of Plant (a)	Character of Modification (b)	Installed Plant Capacity After Modification (in MW) (c)	Estimated Dates of Construction Start (d)	Completion (e)
8	NONE				
9					
10					
11					
12					
13					
14					

C. New Generating Plants Scheduled for or Under Construction

Line No.	Plant Name and Locatior (a)	Type (Hydro, Pumped Storage, Steam, Internal Combustion Gas-Turbine, Nuclear, etc) (b)	Installed Capacity (in megawatts) Initial (c)	Ultimate (d)	Estimated Dates of Construction Start (e)	Completion (f)
15	NONE					
16						
17						
18						
19						
20						
21						

D. New Units in Existing Plants Scheduled for or Under Construction

Line No.	Plant Name and Locatior (a)	Type (Hydro, Pumped Storage, Steam, Internal Combustion Gas-Turbine, Nuclear, etc) (b)	Unit No. (c)	Size of Unit (in megawatts) (d)	Estimated Dates of Construction Start (e)	Completion (f)
22	NONE					
23						
24						
25						
26						
27						
28						

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Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2012

STEAM ELECTRIC GENERATING PLANTS

1. Include on this page steam-electric plants of 25,000 Kw (name plate rating) or more of installed capacity.
2. Report the information called for concerning generating plants and equipment at year end. Show unit type Installation, boiler, and turbine-generator on same line.
3. Exclude plant, the book cost of which is located in Account 121, *Nonutility Property.*
4. Designate any generating plant 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 term of lease, and annual rent. For any generating plant, other than a leased plant or portion therof for which the respondent is not the sole owner but which the respondent operates or share in the of, furnish a succinct statement explaining the arrangement and giving details as to such matters as percent ownership by respondent, name of co-owner, basis of sharing output, expenses or revenues, and how expenses and/or revenues are accounted for and accounts affected. Specify if lessor, co-owner, or other party is an associated company.
5. Designate any generating plant or portion thereof leased to another company and give name of lessee, date and term of lease and annual rent, and how determined. Specify whether lessee is an associated company.
6. Designate any plant or equipment owned, not

Line No.	Name of Plant (a)	Location of Plant (b)	BOILERS (*Include both ratings for the boiler and the turbine-generator or dual-rated installations*)				
			Number and Year Installed (c)	Kind of Fuel And Method of Firing (d)	Rated Pressure (In psig) (e)	Rated Steam Temp. (*Indicate reheat boilers as 1050/1000*) (f)	Rated Max. Continuous M lbs. Steam per Hour (g)
1	Tanners Creek	Lawrenceburg, IN	1-1951	Pulv. Coal	2080	1050/1000	930
2							
3			2-1952	Pulv. Coal	2080	1050/1000	930
4							
5			3-1954	Pulv. Coal	2075	1050/1050	1,335
6							
7			4-1964	Coal-Cyclone	3500	1000/1025	3,840
8						/1050	
9							
10							
11							
12							
13							
14							
15	Donald C. Cook	Bridgman, MI	1-1975	Nuclear	2485	600	15,600
16			2-1978	Nuclear	2485	600	14,740
17							
18							
19							
20							
21	Rockport*	Rockport, IN	1-1984	Pulv. Coal	3650	1000/1000	9,775
22							
23			2-1989	Pulv. Coal	3650	1000/1000	9,775
24							
25							
26							
27							
28	* Figures shown are the totals for the plant which is shared one-half by respondent and one-half						
29	by AEP Generating Company (an associated company). Both companies are subsidiaries of American						
30	Electric Power Company. Operating expenses are shared on the basis of ownership percentage.						
31	Unit 1 is owned 50% by each and unit 2 is leased 50% by each from a consortium of financial institutions.						
32							
33							

Name of Respondent	This Report Is:	Date of Report	Year of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2012

STEAM ELECTRIC GENERATING PLANTS (cont'd)

operated, and not leased to another company. If such plant or equipment was not operated within the past year, explain whether it has been retired in the books of account or what disposition of the plant or equipment and its book cost are contemplated.

7. Report gas-turbines operated in a combined cycle with a conventional steam unit with its associated steam unit.

Turbine-Generators

(Report cross-compound turbine generator units on two lines-H.P. section and I.P. section. Designate units with shaft connected boiler feed pumps. Give capacity rating of pumps in terms of full load requirements.)

	TURBINES (Include both ratings for boiler and turbine-generator of dual-rated installations)				GENERATORS							
					NAME PLATE Rating in Kw							
Year Installed	Max. Rating Mega-Watt	Type (Indicate tandem-compound (TC); cross compound (CC) single casing (SC); topping unit (T); and non-condensing (NC) Show back pressures)	Steam Pressure at Throttle psig.	RPM	At Minimum Hydrogen Pressure	At Max. Hydrogen Pressure (Include both ratings for the boiler and the turbine-generator of dual-rated installations)	Hydrogen Pressure (Designate air cooled generators) Min.	Hydrogen Pressure Max.	Power Factor	Voltage (in MV) (If other than 3 phase, 60 cycle indicate other characteristic)	Plant Capacity Maximum Generator Name Plate Rating (Should agree with column (n))	Line No.
(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	
1951	90	CC	Var.	1800	90,000	109,800	0.5	25	0.80	13.8	152,500	1
1951	35	CC	2000	3600	35,000	42,700	0.5	25	0.80	13.8		2
1952	90	CC	Var.	1800	90,000	109,800	0.5	25	0.80	13.8	152,500	3
1952	35	CC	2000	3600	35,000	42,700	0.5	25	0.80	13.8		4
1954	100	CC	Var.	1800	112,000	137,200	0.5	30	0.80	18	215,400	5
1954	60	CC	2000	3600	63,750	78,200	0.5	30	0.85	18		6
1964	580	CC	Var.	1800	108,000	238,850	0.5	45	0.85	20	579,700	7
1964		CC	3500	3600	108,000	340,850	0.5	45	0.85	20		8
											1,100,100	9
												10
												11
												12
												13
												14
1975	1149	TC	728	1800	771,840	1,152,000	30	75	0.90	26	1,152,000	15
1978	1162	TC	785	1800	933,850	1,133,333	40	60	0.85	26	1,133,333	16
											2,285,333	17
												18
												19
												20
1984	650	CC	600	3600	600,000	650,000	45	65	0.90	26	1,300,000	21
1984	650	CC	3650	3600	600,000	650,000	45	65	0.90	26		22
1989	650	CC	600	3600	600,000	650,000	45	65	0.90	26	1,300,000	23
1989	650	CC	3650	3600	600,000	650,000	45	65	0.90	26		24
											2,600,000	25
												26
												27
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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.
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. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. 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.
6. 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.

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
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	STATE OF INDIANA							
2	6128 DUMONT	JEFFERSON	765.00	765.00	ALUM TOWER	202.76		1
3	6128 DUMONT	JEFFERSON	765.00	765.00	STEEL	0.24		
4	6136 DUMONT	WILTON CENTER	765.00	765.00	STEEL	63.00		1
5	6141 DUMONT	MARYSVILLE	765.00	765.00	STEEL	104.00		1
6	6215 D.C. COOK	DUMONT	765.00	765.00	STEEL	20.00		1
7	6223 ROCKPORT	JEFFERSON	765.00	765.00	STEEL	111.00		1
8	6224 ROCKPORT	SULLIVAN	765.00	765.00	STEEL	97.00		1
9	6226 JEFFERSON	WEST	765.00	765.00				
10	6236 HANGING ROCK	JEFFERSON	765.00	765.00	STEEL	1.00		1
11	0675 TANNERS CREEK	SORENSON	345.00	345.00	STEEL	136.00		2
12	0676 SORENSON	EAST LIMA	345.00	345.00	STEEL	30.00		1
13	0677 BREED	DEQUINE EAST	345.00	345.00	STEEL	188.19		2
14	0678 DEQUINE	OLIVE	345.00	345.00	STEEL	0.45		
15	0679 SORENSON	OLIVE	345.00	345.00	STEEL	78.00		2
16	0680 OLIVE	GOODINGS GROVE	345.00	345.00	STEEL	41.00		2
17	0683 DESOTO	JCT TOWER (MAR. CO)	345.00	345.00	STEEL	53.00	6.00	1
18	0684 TANNERS CREEK	JUNCTION TOWER	345.00	345.00	ST & ALUM	80.00		1
19	0685 HANNA	JUNCTION TOWER	345.00	345.00				
20	0687 TANNERS CREEK	MIAMI FORT	345.00	345.00	STEEL			2
21	0688 EUGENE	SIDNEY	345.00	345.00	WOOD POLE	2.00		1
22	0689 SORENSON-OLIVE	TWIN BRANCH	345.00	345.00	STEEL	11.00		2
23	0690 BREED	CIPSCO	345.00	345.00	STEEL	1.00		1
24	0691 BREED	PETERSBURG	345.00	345.00	STEEL	1.00		1
25	6118 ROBISON PARK	SORENSON-EAST LIMA	345.00	345.00	STEEL	23.00		1
26	6119 COOK	OLIVE	345.00	345.00	STEEL	4.00		2
27	6122 DUMONT	OLIVE	345.00	345.00	STEEL	15.00		2
28	6123 DUMONT	TWIN BRANCH	345.00	345.00	STEEL	17.00		2
29	6125 ROBISON PARK	EAST	345.00	345.00				
30	6133 DUMONT	BABCOCK	345.00	345.00	STEEL	9.00		1
31	6145 TWIN BRANCH	COOK-ROB PARK JCT	345.00	345.00	STEEL	6.00		2
32	6147 COOK	ROBISON PARK	345.00	345.00	STEEL	68.00		2
33	6148 JACKSON ROAD	SORENSON-OLIVE	345.00	345.00	STEEL	4.00		2
34	6213 COOK-ROB-PARK JCT	ARGENTA	345.00	345.00	STEEL	2.00		2
35	6237 JACKSON ROAD	WEST	345.00	345.00				
36					TOTAL	3,931.13	122.54	203

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) / /	End of 2012/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. 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)
8. 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.
9. 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.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								1
4-954 MCM	2,885,193	44,045,181	46,930,374					2
4-954 MCM								3
4-954 MCM	1,542,558	9,393,863	10,936,421					4
4-954 MCM	1,234,793	19,788,959	21,023,752					5
4-954 MCM	431,470	5,244,378	5,675,848					6
4-1351 MCM	6,290,324	89,243,898	95,534,222					7
4-1351 MCM	14,100,277	67,827,548	81,927,825					8
	761,721	9,497	771,218					9
4-1351 MCM	31,637	766,942	798,579					10
1275 MCM	667,658	12,385,879	13,053,537					11
1275 MCM	107,576	1,563,129	1,670,705					12
1414 MCM	533,312	12,823,755	13,357,067					13
2303 ACSR 54/37	481,571	11,958,809	12,440,380					14
1414 MCM	447,262	7,970,440	8,417,702					15
1414 MCM	429,643	4,672,226	5,101,869					16
2-954 MCM	513,937	3,976,476	4,490,413					17
2-954 MCM	457,068	6,585,480	7,042,548					18
	232,250	717,371	949,621					19
2-954 MCM		197,170	197,170					20
1414 MCM	10,088	602,243	612,331					21
1563 MCM	228,725	1,781,982	2,010,707					22
2-1024 MCM		314,122	314,122					23
2-954 MCM		188,845	188,845					24
1414 MCM	169,866	2,753,663	2,923,529					25
2-954 MCM	30,751	1,134,850	1,165,601					26
2-954 MCM	180,037	2,836,290	3,016,327					27
2-954 MCM	344,829	3,542,279	3,887,108					28
	173,109		173,109					29
2-954 MCM	163,248	1,253,123	1,416,371					30
2-954 MCM	60,475	1,340,352	1,400,827					31
2-954 MCM	1,604,704	14,643,414	16,248,118					32
2303 MCM	219,514	1,040,472	1,259,986					33
2-954 MCM	95,761	909,779	1,005,540					34
	47,407		47,407					35
	58,448,283	573,637,400	632,085,683	151,087	6,623,662		6,774,749	36

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.
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. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. 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.
6. 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.

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
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	6240 TWIN BRANCH	SUBSTATION CORRIDOR	345.00	345.00				
2	6256 BREED	SULLIVAN	345.00	345.00	STEEL	2.00		2
3	6259 COLLINGWOOD	SOUTH BUTLER	345.00	345.00	STEEL POLE	12.00		1
4	6127 EAST ELKHART TAP		138.00	138.00				
5	6232 GODMAN TAP		34.00	138.00				
6	0602 TWIN BRANCH	RIVERSIDE	138.00	138.00	STEEL	6.00		2
7	0603 TWIN BRANCH	SOUTH BEND	138.00	138.00	STEEL	5.00		1
8	0604 TWIN BRANCH	ROBISON PARK	138.00	138.00	STEEL	65.00		2
9	0605 SOUTH BEND	MICHIGAN CITY	138.00	138.00	STEEL			1
10	0606 ROBISON PARK	HAVILAND	138.00	138.00	STEEL	20.00		2
11	0607 ROBISON PARK	DEER CREEK	138.00	138.00	STEEL	60.00		2
12	0608 DEER CREEK	KOKOMO	138.00	138.00	STEEL	7.00		1
13	0609 CONCORD TAP		138.00	138.00	STEEL	4.00		2
14	0613 TWIN BRANCH	JACKSON ROAD	138.00	138.00	STEEL	8.00		2
15	0614 LINCOLN TAP		138.00	138.00	STEEL	4.00		2
16	0615 TWIN BRANCH	ROBISON PARK	138.00	138.00	STEEL	65.83		1
17	0616 DEER CREEK	DELAWARE	138.00	138.00	STEEL	24.50		2
18	0617 DELAWARE	MADISON	138.00	138.00	STEEL	19.00		2
19	0618 DELAWARE	COLLEGE CORNER	138.00	138.00	STEEL TWR &	56.31		2
20	0618 DELAWARE	COLLEGE CORNER	138.00	138.00	UNDERGROU	1.69		2
21	0725 DELAWARE	TRENTON	138.00	138.00	STEEL TWR &			
22	0619 MADISON	NEW CASTLE	138.00	138.00	STEEL	6.00	1.00	1
23	0620 TANNERS CREEK	MADISON	138.00	138.00	STEEL	82.00		2
24	0622 JACKSON ROAD	OLIVE	138.00	138.00	STEEL	17.00	1.00	1
25	0623 MADISON	PENDLETON	138.00	138.00	WOOD &	5.00		1
26	0624 DRAGOON TAP		138.00	138.00	STEEL	2.00		1
27	0625 TANNERS CREEK	COLLEGE CORNER	138.00	138.00	STEEL	40.00		2
28	0626 COLLEGE CORNER	RANDOLPH	138.00	138.00	WOOD	39.00		1
29	0627 RANDOLPH	JAY	138.00	138.00	WOOD	24.00		1
30	0628 MCKINLEY TAP		138.00	138.00	STEEL	1.00		2
31	0629 JAY	LINCOLN	138.00	138.00	WOOD &	49.00		1
32	0630 NEW CARLISLE	MAPLE	138.00	138.00	WOOD	1.00		1
33	6104 SORENSON	DEVILS HOLLOW	138.00	138.00	STEEL	3.00		2
34	0632 SORENSON	DEVILS HOLLOW	138.00	138.00	STEEL			
35	0634 DEER CREEK	MULLIN	138.00	138.00	WOOD	15.00		1
36					TOTAL	3,931.13	122.54	203

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. 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)
8. 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.
9. 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.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
	8,817		8,817					1
1351.5 MCM		1,580,285	1,580,285					2
2-954 MCM	652,439	3,138,865	3,791,304					3
	6,269	126,553	132,822					4
	10,045	93,336	103,381					5
397.5 MCM	89,823	317,682	407,505					6
397.5 MCM	109,232	337,821	447,053					7
397.5 MCM	104,914	1,947,803	2,052,717					8
397.5 MCM	112,011	2,958,657	3,070,668					9
397.5 MCM	26,662	788,903	815,565					10
397.5 MCM	146,959	2,381,394	2,528,353					11
336.4 MCM	20,552	387,202	407,754					12
397.5 MCM	45,025	368,110	413,135					13
447 MCM	100,708	908,587	1,009,295					14
397.5 MCM	48,572	134,586	183,158					15
477 MCM	317,644	2,142,745	2,460,389					16
397.5 MCM	57,269	1,188,353	1,245,622					17
397.5 MCM	82,081	498,712	580,793					18
397.5 MCM	233,078	1,052,510	1,285,588					19
397.5 MCM								20
397.5 MCM		1,360,786	1,360,786					21
795 MCM	39,152	279,395	318,547					22
636 MCM	420,806	3,573,981	3,994,787					23
556.5 MCM	187,920	1,064,021	1,251,941					24
477 MCM	64,558	282,309	346,867					25
795 MCM	18,502	160,276	178,778					26
636 MCM	178,525	1,652,881	1,831,406					27
556.5 MCM	196,883	2,302,354	2,499,237					28
556.5 MCM	133,748	1,055,169	1,188,917					29
300 MCM CU	38,296	134,814	173,110					30
556.5 MCM	207,712	1,952,962	2,160,674					31
397.5 MCM	2,242	32,335	34,577					32
556.5 MCM	35,618	568,717	604,335					33
556.5 MCM	40,380	1,975,339	2,015,719					34
556.5 MCM	126,238	551,470	677,708					35
	58,448,283	573,637,400	632,085,683	151,087	6,623,662		6,774,749	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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.
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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	0635 PENDLETON	MULLIN	138.00	138.00	WOOD &	16.00		1
2	0636 DEER CREEK	FISHER BODY	138.00	138.00	STEEL	5.04		2
3	0637 TWIN BRANCH	CONCORD	138.00	138.00	STEEL	17.00	1.00	1
4	0638 GRANT	FISHER BODY	138.00	138.00	STEEL		1.00	1
5	0639 ROBISON PARK	AUBURN	138.00	138.00	WOOD &	15.00		1
6	0641 DESOTO	MEDFORD	138.00	138.00	STEEL	7.00		2
7	0642 OLIVE	HICKORY CREEK	138.00	138.00	STEEL	3.00	2.00	1
8	0645 COREY TAP		138.00	138.00	WOOD	4.00		1
9	0646 OLIVE	NEW CARLISLE	138.00	138.00	STEEL	2.00		1
10	0647 OLIVE	SOUTH BEND	138.00	138.00	STEEL	1.00	16.00	1
11	0648 MEDFORD TAP		138.00	138.00	STEEL	8.00		2
12	0714 EAST SIDE STA ENTR		138.00	138.00	UNDERGROU			1
13	0723 SPY RUN STATION		138.00	138.00	UNDERGROU			1
14	6101 WESTINGHOUSE TAP		138.00	138.00	STEEL	2.00		2
15	6102 MILAN TAP		138.00	138.00	STEEL	6.00		2
16	6103 MILAN	GOODRICH	138.00	138.00	STEEL	1.00		2
17	6105 DESOTO	JAY	138.00	138.00	WOOD &	13.00		1
18	6106 DESOTO	DEER CREEK-DELAWARE	138.00	138.00	STEEL	8.00		2
19	6107 DARDEN TAP		138.00	138.00	WOOD	1.00		1
20	6109 ROBISON PARK	RICHLAND	138.00	138.00	WOOD &	18.00		1
21	6110 WESTINGHOUSE	23RD STREET	138.00	138.00	STEEL			2
22	6111 KANKAKEE	WEST SIDE	138.00	138.00	WOOD POLE	2.00		1
23	6113 INDUSTRIAL PARK		138.00	138.00	STEEL	3.00		2
24	6114 OLIVE	MICHIGAN CITY	138.00	138.00	STEEL	2.00	1.00	1
25	6115 HUMMEL CREEK	VAN BUREN	138.00	138.00	STEEL	6.00		2
26	6130 HUMMEL CREEK	TOWER 70, GREENTOWN	138.00	138.00				
27	6116 SOUTH ELWOOD TAP		138.00	138.00	WOOD POLE	3.00		1
28	6117 PENDLETON	FALL CREEK	138.00	138.00	STEEL	10.00		2
29	6121 ROBISON PARK	LINCOLN	138.00	138.00	STEEL	8.00		1
30	6126 CONCORD	EAST ELKHART	138.00	138.00	STEEL	11.00		1
31	6129 GREENTOWN-GRANT	HUMMEL CREEK	138.00	138.00	STEEL	21.00		1
32	6131 INDUSTRIAL PARK	MC KINLEY	138.00	138.00	WOOD POLE	5.00		1
33	6132 CROSS STREET TAP	JUNCTION TOWER #88	138.00	138.00	WOOD POLE	4.00		1
34	6134 LINCOLN	ANTHONY	138.00	138.00	WOOD POLE	3.00		1
35	6135 WAYNEDALE TAP		138.00	138.00	STEEL			2
36					TOTAL	3,931.13	122.54	203

TRANSMISSION LINE STATISTICS (Continued)

7. 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)
8. 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.
9. 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.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
556.5 MCM	124,403	458,758	583,161					1
397.5 MCM	41,365	204,739	246,104					2
556.5 MCM	180,274	829,827	1,010,101					3
397.5 MCM	2,880	48,472	51,352					4
556.5 MCM	76,321	594,637	670,958					5
556.5 MCM	75,010	280,989	355,999					6
556.5 MCM	23,973	177,628	201,601					7
477 MCM	29,668	317,100	346,768					8
556.5 MCM	20,280	155,782	176,062					9
556.5 MCM		231,976	231,976					10
556.5 MCM	125,413	310,892	436,305					11
795 MCM		724,752	724,752					12
3.5IN OD		398,528	398,528					13
556.5 MCM	31,370	80,037	111,407					14
397.5 MCM	35,398	226,349	261,747					15
397.5 MCM	1,694	31,137	32,831					16
2-556.5 MCM	67,227	562,318	629,545					17
636 MCM	63,247	339,836	403,083					18
336.4 MCM	5,232	719,390	724,622					19
636 MCM	123,078	718,259	841,337					20
556.5 MCM	13,643	60,184	73,827					21
636 MCM	19,773	177,907	197,680					22
745 MCM	32,372	436,056	468,428					23
636 MCM	15,878	189,366	205,244					24
795 MCM	40,836	486,308	527,144					25
	44,222	584,596	628,818					26
556.5 MCM	5,090	678,826	683,916					27
795 MCM	150,802	1,001,340	1,152,142					28
795 MCM	677	1,038,982	1,039,659					29
795 MCM	179,506	986,412	1,165,918					30
795 MCM	180,124	1,321,738	1,501,862					31
795 MCM	75,257	342,579	417,836					32
795 MCM	262,613	192,719	455,332					33
795 MCM	90,524	634,972	725,496					34
795 MCM	22,040	71,621	93,661					35
	58,448,283	573,637,400	632,085,683	151,087	6,623,662		6,774,749	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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.
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. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. 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.
6. 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.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	6138 JACKSON ROAD	SOUTH SIDE	138.00	138.00	WOOD POLE	2.00		1
2	6142 ALBION	KENDALLVILLE	138.00	138.00	WOOD POLE	10.00		1
3	6150 SOUTHSIDE	SOUTH BEND	138.00	138.00	WOOD &	6.07		1
4	6219 DELCO BATTERY TAP		138.00	138.00	STEEL POLE	1.00		2
5	6220 FALL CREEK	MADISON-NEW CASTLE	138.00	138.00	STEEL	1.00		2
6	6225 INDUSTRIAL PARK	SPY RUN	138.00	138.00	WOOD POLE	4.00		1
7	6266 WALLEN		138.00	138.00	STEEL POLE	0.22		1
8	6234 CABOT TAP/CR 4	EAST ELKHART	138.00	138.00	WOOD POLE	0.13		1
9	6238 SORENSON	MCKINLEYTOWER	138.00	138.00	STEEL	3.00		2
10	6241 KENDALLVILLE TAP	CITY OF AUBURN #5	138.00	138.00	WOOD H-FR	14.00		1
11	6242 AUBURN	CITY OF AUBURN #5	138.00	138.00	WOOD POLE	2.00		1
12	6245 LAPORTE JCT	LIQUID CARBONICS	138.00	138.00	WOOD POLE	5.00		1
13	6246 LAPORTE JCT	AIRCO	138.00	138.00	WOOD POLE	1.00		1
14	6248 ELCONA TAP	CONC-DUN-E-ELK	138.00	138.00	WOOD POLE	2.00		1
15	6249 ALLEN	LINCOLN	138.00	138.00	STEEL	5.00		2
16	6250 ALLEN	ADAMS/HILLCREST	138.00	138.00	STEEL	5.00		2
17	6251 OLIVE	EDISON	138.00	138.00	STEEL	1.00		2
18	6253 TRIER RD TAP		138.00	138.00	STEEL POLE			1
19	6258 KENZIE CREEK	TWIN BRANCH	138.00	138.00	STEEL			2
20	6260 WILMINGTON TAP		138.00	138.00	WOOD POLE	1.00	9.00	1
21	6229 DUNLAP NORTH TAP		34.00	138.00	WOOD POLE	2.00		2
22	6140 INDIANA-PURDUE		34.00	138.00	STEEL POLE			2
23	6217 HILLCREST	KINNERK	69.00	138.00	WOOD POLE	4.00		1
24	6252 KENDALLVILLE	BIXLER	138.00	138.00	WOOD POLE	2.00		1
25	6254 ALLEN/LINCOLN	ALLEN/HILLCREST	138.00	138.00				
26	6265 CONCORD	WOLF	138.00	138.00	WOOD POLE	0.56	0.54	1
27	INDALEX TAP/CR 4	EAST ELKHART	138.00	138.00	WOOD POLE	1.09		
28	6267 STUDEBAKER	WEST SIDE	138.00	138.00	WOOD POLE	1.41		1
29			138.00	138.00	STEEL	1.11		1
30	6270 JONES CREEK	HOGAN	138.00	138.00		5.62		
31	LINES<132 KV	SYSTEM	69.00		WOOD,	924.12	72.00	1
32								
33	STATE OF MICHIGAN							
34	6216 D.C. COOK	DUMONT	765.00	765.00	STEEL	16.00		1
35	6120 COOK	PALISADES	345.00	345.00	STEEL	42.00		2
36					TOTAL	3,931.13	122.54	203

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. 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)
8. 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.
9. 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.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
795 MCM	1,633	664,597	666,230					1
795 MCM	77,153	539,898	617,051					2
795 MCM	321,978	1,955,476	2,277,454					3
795 MCM AA	47,993	59,531	107,524					4
795 MCM	65,007	307,522	372,529					5
1033 MCM	91,134	603,198	694,332					6
1033.5 KCM		484,324	484,324					7
556.5 MCM		39,158	39,158					8
795 MCM	157,782	1,140,939	1,298,721					9
795 MCM	694,850	2,341,025	3,035,875					10
795 MCM	61,515	370,703	432,218					11
795 MCM	58,646	1,030,934	1,089,580					12
795 MCM	45,547	267,987	313,534					13
795 MCM	87,386	557,013	644,399					14
1033 MCM	23,500	1,658,390	1,681,890					15
1033 MCM		1,723,802	1,723,802					16
795 MCM	202,537	688,549	891,086					17
795 MCM		69,888	69,888					18
1033 MCM		136,604	136,604					19
2-954 MCM		1,365,463	1,365,463					20
795 MCM	10,443	304,289	314,732					21
1033 MCM	428	127,388	127,816					22
795 MCM	47,490	265,025	312,515					23
795 MCM	118,432	760,317	878,749					24
	385,522		385,522					25
336.4 ACSR KCM								26
		651,251	651,251					27
954 MCM	184,975	2,362,898	2,547,873					28
954 MCM								29
	1,479,352	5,732,715	7,212,067					30
VARIOUS	4,264,228	92,120,768	96,384,996					31
								32
								33
4-954 MCM	871,513	3,562,229	4,433,742					34
2-954 MCM	1,073,200	6,060,899	7,134,099					35
	58,448,283	573,637,400	632,085,683	151,087	6,623,662		6,774,749	36

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.
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. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. 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.
6. 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.

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
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	6143 D.C. COOK	OLIVE-PALISADES	345.00	345.00	STEEL	5.00		2
2	6144 TWIN BRANCH	COOK-ROB PARK JCT	345.00	345.00	STEEL			2
3	6151 COOK	OLIVE	345.00	345.00				
4	6152 COOK	ROBINSON PARK	345.00	345.00				
5	6146 D.C. COOK	ROBISON PARK	345.00	345.00	STEEL	37.00		2
6	6214 COOK-ROB PARK	ARGENTA	345.00	345.00	STEEL	29.00		2
7	6221 D.C. COOK	OLIVE-PALISADES	345.00	345.00	STEEL	5.00		2
8	6263 BARODA TAP		138.00	138.00				
9	0601 TWIN BRANCH	RIVERSIDE	138.00	138.00	STEEL	33.00		2
10	0610 AUTO SPECIALTIES		138.00	138.00				
11	0621 TWIN BRANCH - R	HICKORY CREEK	138.00	138.00	STEEL	5.00		2
12	0644 RIVERSIDE	HARTFORD	138.00	138.00	WOOD	16.33		1
13	0649 COREY TAP		138.00	138.00	WOOD	13.00		1
14	6108 RIVERSIDE	OLIVE-HICKORY CREEK	138.00	138.00	WOOD &	6.00		1
15	6124 BENTON HARBOR	RIVERSIDE-HARTFORD	138.00	138.00	STEEL	1.00		2
16	6137 EDGEWATER TAP		138.00	138.00	WOOD POLE	0.76		1
17	6139 BENTON HARBOR	TWIN BRANCH-R SIDE	138.00	138.00	STEEL	6.00		2
18	6149 HARTFORD	COREY	138.00	138.00	WOOD POLE	41.00		1
19	6218 MOTTVILLE TAP		138.00	138.00	WOOD POLE	1.00		1
20	6255 KENZIE CREEK	VALLEY	138.00	138.00	WOOD POLE	20.00		1
21	6257 KENZIE CREEK	T B/R'SIDE/HICK CR	138.00	138.00	STEEL			
22	6261 FLATBUSH TAP		138.00	138.00		1.00		1
23	6262 WEST ST TAP		138.00	138.00		1.00		2
24	6700 GM HYDRAMATIC		138.00	138.00	STEEL	2.00		2
25	6227 NICKERSON	TOWER #13A	138.00	138.00				
26	0643 OLIVE	HICKORY CREEK	138.00	138.00				
27	6268 SAUK TRAIL		138.00	138.00	STEEL	1.60		
28	LESS THAN 132 KV LINES		69.00		WOOD,	425.10	12.00	
29								
30	VOLTAGE OTHER							
31	VOLTAGE 765KV							
32	VOLTAGE 345KV							
33	VOLTAGE 138KV							
34	VOLTAGE LESS THAN 132							
35								
36					TOTAL	3,931.13	122.54	203

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. 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)
8. 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.
9. 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.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
2-954 MCM	722,573	1,183,640	1,906,213					1
2-954 MCM		297,770	297,770					2
		1,609,360	1,609,360					3
	12,355		12,355					4
2-954 MCM	1,373,242	7,464,515	8,837,757					5
2-954 MCM	861,975	5,263,324	6,125,299					6
2-954 MCM		1,894,767	1,894,767					7
		-8,230	-8,230					8
397.5 MCM	210,485	1,086,387	1,296,872					9
	821		821					10
397.5 MCM	51,083	307,583	358,666					11
397.5 MCM	117,604	1,137,254	1,254,858					12
477 MCM	73,434	312,859	386,293					13
636 MCM	72,387	1,000,401	1,072,788					14
795 MCM	88,699	168,142	256,841					15
556.5 MCM	604	58,612	59,216					16
795 MCM	472,534	628,432	1,100,966					17
795 MCM	798,073	2,642,545	3,440,618					18
795 AA	16,279	100,911	117,190					19
1033 MCM	579,785	5,034,991	5,614,776					20
795 MCM		383,038	383,038					21
	64,293	430,007	494,300					22
	24,993	331,419	356,412					23
795 MCM	10,463	370,087	380,550					24
		151,111	151,111					25
	171,679	1,190,287	1,361,966					26
1033.5KCM	271,564	2,429,016	2,700,580					27
VARIOUS	1,581,480	25,790,052	27,371,532					28
								29
								30
				22,922	1,004,905		1,027,827	31
				33,829	1,483,076		1,516,905	32
				40,917	1,793,812		1,834,729	33
				53,419	2,341,869		2,395,288	34
								35
	58,448,283	573,637,400	632,085,683	151,087	6,623,662		6,774,749	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)	(c)	Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
1	NO LINES ADDED						
2							
3	NO LINES ALTERED						
4							
5							
6							
7							
8							
9							
10							
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40							
41							
42							
43							
44	TOTAL						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

TRANSMISSION LINES ADDED DURING YEAR (Continued)

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.

CONDUCTORS			Voltage KV (Operating) (k)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)		Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
									1
									2
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									4
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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).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	ADAMS (IM)-IN	T	138.00	69.00	34.00
2		T	34.50	13.00	
3	ALBION-IN	T	138.00	69.00	12.00
4		T	138.00		
5		T	69.00	12.00	
6		T	69.00		
7	ALEXANDRIA-IN	D	34.50	13.00	
8		D	34.50	4.00	
9		D	34.50		
10	ALLEN (IM)-IN	T	345.00	137.50	13.80
11	ALMENA-MI	T	69.00	34.50	
12		T	69.00	34.00	
13		T	69.00	12.00	
14	ANCHOR HOCKING (IM)-IN	D	69.00	13.00	
15		D	69.00	2.40	
16	ANTHONY-IN	T	138.00	34.00	
17		T	34.50	12.00	
18	ARMSTRONG CORK-IN	D	69.00	4.00	
19	ARNOLD HOGAN-IN	T	138.00	34.00	
20		T	138.00	13.09	
21		T	34.50		
22	AUBURN-IN	T	138.00	69.00	34.00
23		T	138.00		
24	BARODA-MI	D	138.00	13.09	
25	BEECH ROAD-IN	D	138.00	13.09	
26	BENTON HARBOR-MI	T	345.00	137.50	13.80
27		T	345.00	137.50	13.14
28	BERNE-IN	D	69.00	12.00	
29		D	69.00		
30	BERRIEN SP HYDR STAT-MI	T	34.50	13.00	
31		T	34.50	12.00	
32		T	34.50		
33	BETHEL-IN	D	34.50	13.00	
34	BIXLER-IN	D	138.00	13.09	
35	BLAINE STREET-IN	D	34.50	13.00	
36	BLUFF POINT-IN	T	138.00	69.50	13.09
37		T	69.00	13.00	
38		T	69.00		
39	BREED-IN	T	345.00		
40		T	345.00	14.40	

SUBSTATIONS (Continued)

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.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
115	1					1
4	1					2
90	1					3
			STATCAP	1	53	4
8	1					5
			STATCAP	1	14	6
22	1					7
6	1					8
			STATCAP	1	7	9
450	1					10
30	1					11
22	1					12
7	1					13
20	1					14
14	2					15
112	1					16
29	2					17
20	2					18
30	1					19
22	1					20
			STATCAP	2	29	21
30	1					22
			STATCAP	2	106	23
20	1					24
20	1					25
450	1					26
224		1				27
20	1					28
			STATCAP	1	16	29
5	1					30
5	1					31
			STATCAP	1	10	32
11	1					33
20	1					34
29	2					35
60	1					36
6	1					37
			STATCAP	1	16	38
			REACTOR	1	250	39
65	1					40

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).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	BRIDGMAN-MI	D	69.00	12.00	
2		D	69.00		
3	BUCHANAN HYDRO STA-MI	T	69.00	34.00	
4		T	69.00	12.00	
5	BUCHANAN SOUTH-MI	D	69.00	12.00	
6	BUTLER (IM)-IN	D	69.00	13.00	
7		D	69.00		
8	CALVERT-IN	D	138.00	13.09	
9	CHURUBUSCO-IN	D	34.50	13.00	
10		D	34.50		
11	CLEVELAND-IN	D	138.00	13.09	
12	COLBY-MI	T	138.00	69.00	34.50
13		T	138.00	13.09	
14		T	69.00	34.50	
15		T	34.50		
16	COLFAX-IN	D	34.50	12.00	
17	COLOMA Y-MI	T	69.00	34.00	
18		T	69.00		
19	COLONY BAY-IN	D	69.00	13.00	
20		D	69.00	12.00	
21	COLUMBIA(IM)-IN	T	138.00	69.00	34.00
22		T	138.00	34.00	
23	CONANT-IN	D	34.50	12.00	
24	CONCORD-IN	T	138.00	34.00	
25		T	138.00	13.09	
26		T	138.00		
27		T	34.50		
28	COREY-MI	T	138.00	69.00	34.50
29		T	69.00		
30	COUNTRYSIDE-IN	D	138.00	12.47	
31	COUNTY LINE (IM)-IN	D	138.00	13.09	
32	COUNTY ROAD 4-IN	D	138.00	13.09	
33	CROSS STREET-IN	D	138.00	13.09	
34	CRYSTAL-MI	D	138.00	13.09	
35	DALEVILLE-IN	D	138.00	13.09	
36	DARDEN ROAD-IN	D	138.00	13.09	
37	DC COOK EHV-MI	T	765.00	345.00	34.00
38					
39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

SUBSTATIONS (Continued)

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.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
19	2					1
			STATCAP	1	14	2
20	1					3
8	1					4
22	1					5
20	1					6
			STATCAP	2	30	7
20	1					8
11	1					9
			STATCAP	1	5	10
20	1					11
75	1					12
8	1					13
20	1					14
			STATCAP	1	17	15
22	1					16
22	1					17
			STATCAP	1	14	18
22	1					19
20	1					20
50	1					21
20	1					22
22	1					23
50	1					24
45	2					25
			STATCAP	1	53	26
			STATCAP	1	14	27
130	1					28
			STATCAP	1	14	29
20	1					30
20	1					31
20	1					32
20	1					33
22	1					34
20	1					35
42	2					36
1500	3	1				37
						38
						39
						40

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).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	DECATUR (FTW)-IN	T	69.00	34.00	
2		T	69.00	13.00	
3		T	69.00	4.00	
4		T	69.00		
5	DEER CREEK-IN	T	138.00	69.00	34.00
6		T	138.00	34.50	
7		T	138.00	13.09	
8		T	138.00		
9		T	34.50	13.09	
10		T	34.50	11.00	4.00
11		T	34.50		
12	DELAWARE (IM)-IN	T	138.00	34.00	
13		T	138.00		
14		T	34.50		
15	DERBY-MI	T	138.00	69.00	34.50
16	DESOTO-IN	T	345.00	138.00	34.50
17	DIEBOLD ROAD-IN	D	69.00	13.00	
18	DOOVILLE-IN	D	138.00	13.09	
19	DRAGOON-IN	T	138.00	69.00	34.00
20		T	34.50		
21	DREWRYS-IN	D	34.50	13.09	
22		D	34.50	12.00	
23	DUMONT-IN	T	765.00		
24		T	765.00	345.00	34.50
25		T	765.00	345.00	17.00
26	DUNLAP-IN	T	138.00	69.00	34.00
27		T	138.00	13.09	
28		T	34.50		
29	EAST ELKHART-IN	T	345.00	137.50	13.80
30		T	138.00	69.00	34.00
31		T	34.50	7.20	
32	EAST SIDE (IM)-IN	D	138.00	13.09	
33	ELCONA-IN	D	138.00	13.09	
34	ELKHART HYDRO STAT-IN	T	34.50	13.00	
35		T	34.50		
36	ELMRIDGE-IN	D	34.50	13.00	
37	ELWOOD (IM)-IN	D	34.50	13.00	
38		D	34.50		
39	FAIRMOUNT-IN	D	34.50	7.20	
40	FALL CREEK-IN	T	345.00	138.00	34.00

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) / /	End of 2012/Q4

SUBSTATIONS (Continued)

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.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
20	1					1
20	1					2
5	1					3
			STATCAP	1	13	4
90	1					5
75	1					6
20	1					7
			STATCAP	1	58	8
4	1					9
20	1					10
			STATCAP	2	30	11
125	2					12
			STATCAP	1	53	13
			STATCAP	2	59	14
75	1					15
675	1					16
20	1					17
12	1					18
84	1					19
			STATCAP	1	12	20
8	1					21
8	1					22
			REACTOR	9	750	23
1500	3					24
1500	3					25
130	1					26
40	2					27
			STATCAP	1	29	28
450	1					29
84	1					30
1		1				31
45	2					32
22	1					33
8	1					34
			STATCAP	1	14	35
9	1					36
19	2					37
			STATCAP	1	5	38
11	1					39
672	1					40

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).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	FERGUSON-IN	D	69.00	13.00	
2	FISHER BODY-IN	D	138.00	13.80	
3	FLORENCE ROAD-MI	D	69.00	12.00	
4		D	69.00		
5	FULTON (IM)-IN	D	34.50	13.00	
6	GARRETT (IM)-IN	T	69.00	34.00	
7		T	34.50	13.00	
8	GAS CITY-IN	D	34.50	13.00	
9		D	34.50		
10	GASTON-IN	D	138.00	13.00	4.00
11	GATEWAY (IM)-IN	T	69.00	34.00	
12		T	69.00		
13	GE TAYLOR STREET-IN	T	34.50	13.00	
14	GERMAN-IN	D	138.00	13.09	
15	GLENBROOK-IN	D	34.50	13.00	
16	GRABILL-IN	D	138.00	13.09	
17	GRANGER-IN	D	138.00	13.09	
18		D	138.00	12.47	
19	GRANT-IN	T	138.00	34.00	
20		T	138.00	13.09	
21	GREENLEAF-IN	D	34.50	13.09	
22	GREENTOWN-IN	T	765.00		
23	HACIENDA-IN	D	138.00	13.09	
24		D	138.00	12.47	
25	HADLEY-IN	D	69.00	13.00	
26	HAGAR-MI	D	69.00	12.00	
27	HAMILTON-IN	D	69.00	13.00	
28	HARLAN-IN	D	69.00	13.09	
29		D	69.00	13.00	
30	HARPER-IN	D	138.00	13.09	
31	HARTFORD-MI	T	138.00	69.00	34.00
32		T	69.00	12.00	
33	HARTFORD CITY-IN	T	69.00	34.00	
34		T	69.00	13.00	
35		T	69.00		
36	HARVEST PARK-IN	D	34.50	13.00	
37	HAWTHORNE-MI	D	69.00	12.00	
38	HAYMOND-IN	D	34.50	13.00	
39					
40					

SUBSTATIONS (Continued)

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.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
20	1					1
100	2					2
20	1					3
			STATCAP	1	19	4
20	1					5
10	1					6
1	3					7
20	1					8
			STATCAP	1	10	9
6	1					10
20	1					11
			STATCAP	1	13	12
29	4					13
47	2					14
40	2					15
20	1					16
20	1					17
20	1					18
30	1					19
	1					20
20	1					21
			REACTOR	3	300	22
20	1					23
25	1					24
40	2					25
11	1					26
11	1					27
13	1					28
5	1					29
20	1					30
129	1					31
11	1					32
20	1					33
20	1					34
			STATCAP	1	16	35
20	1					36
22	1					37
24	2					38
						39
						40

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).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	HICKORY CREEK-MI	T	138.00	69.00	34.50
2		T	138.00	34.50	
3		T	34.50	12.00	
4		T	34.50		
5	HILLCREST-IN	T	138.00	69.00	34.00
6		T	138.00	13.09	
7		T	138.00		
8	HUMMEL CREEK-IN	T	138.00	69.00	34.00
9		T	138.00	13.09	
10	ILLINOIS ROAD-IN	T	138.00	69.00	13.00
11		T	138.00	13.09	
12	INDUSTRIAL PARK-IN	T	138.00	69.00	34.00
13		T	138.00	13.09	
14		T	138.00		
15		T	34.50	13.00	
16		T	34.50		
17	IRELAND ROAD-IN	D	138.00	13.09	
18	IU PURDUE-IN	D	34.50	13.00	
19		D	34.50	12.00	
20		D	13.80	4.00	
21	JACKSON ROAD-IN	T	345.00	138.00	34.00
22		T	138.00	34.00	
23		T	138.00	13.09	
24		T	34.50		
25	JAY (IM)-IN	T	138.00	69.00	34.00
26		T	138.00	13.09	
27		T	138.00		
28	JEFFERSON (IM)-IN	T	765.00		
29		T	765.00	345.00	34.00
30		T	138.00		
31	JONES CREEK-IN	D	138.00	12.47	
32	KANKAKEE-IN	T	138.00	34.00	11.00
33		T	138.00	13.09	
34	KENDALLVILLE-IN	T	138.00	69.00	13.00
35		T	138.00		
36		T	69.00	13.00	
37		T	69.00	12.00	
38	KENZIE CREEK-MI	T	345.00	137.50	13.80
39	KLINE-IN	T	138.00	34.00	
40		T	34.50		

SUBSTATIONS (Continued)

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.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
75	1					1
60	2					2
31	2					3
			STATCAP	1	31	4
84	1					5
42	2					6
			STATCAP	1	53	7
75	1					8
20	1					9
84	1					10
20	1					11
75	1					12
22	1					13
			STATCAP	1	50	14
22	1					15
			STATCAP	1	16	16
20	1					17
20	1					18
22	1					19
5	1					20
672	1					21
30	1					22
32	2					23
			STATCAP	1	14	24
115	1					25
9	1					26
			STATCAP	1	58	27
			REACTOR	9	750	28
1500	3					29
			REACTOR	1	20	30
20	1					31
50	1					32
22	1					33
75	1					34
			STATCAP	1	43	35
8	1					36
11	1					37
450	1					38
100	1					39
			STATCAP	1	14	40

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.
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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).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	LAKE STREET-MI	T	69.00	34.00	
2		T	69.00		
3	LAKEHEAD-MI	D	69.00	13.00	
4	LANGLEY (IM)-MI	D	34.50	13.00	
5	LANTERN PARK-IN	D	138.00	13.09	
6	LAPORTE JUNCTION-IN	T	138.00	69.00	34.00
7	LIGONIER-IN	D	138.00	13.09	
8	LINCOLN-IN	T	138.00	34.00	11.00
9		T	138.00	13.09	
10		T	138.00		
11		T	34.50		
12	LINWOOD (IM)-IN	D	138.00	13.09	
13	LUSHER AVENUE-IN	D	34.50	12.00	
14	LYDICK-IN	D	34.50	13.09	
15	MADISON (IM)-IN	T	138.00	35.00	
16		T	34.50	13.09	
17	MAGLEY-IN	T	138.00	69.00	13.00
18		T	69.00	13.00	
19	MAIN STREET-MI	T	138.00	34.00	
20		T	138.00	13.09	
21		T	34.50	4.00	
22		T	34.50		
23	MARATHON OIL (IM)-IN	D	69.00	4.00	
24	MARION ETHANOL-IN	D	34.50	4.00	
25	MARION PLANT-IN	D	34.50	13.00	
26		D	34.50	4.00	
27		D	34.50		
28	MAYFIELD-IN	D	138.00	13.09	
29	MCGALLIARD ROAD-IN	D	34.50	13.00	
30	MCKINLEY-IN	T	138.00	69.00	34.00
31		T	138.00	34.00	
32		T	138.00	13.09	
33		T	138.00		
34		T	69.00		
35		T	34.50		
36	MEADOWBROOK-IN	T	138.00	35.00	
37		T	34.50		
38	MEDFORD-IN	T	138.00	69.00	34.00
39		T	34.50		
40	MIER-IN	D	138.00	13.09	

SUBSTATIONS (Continued)

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.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
40	1					1
			STATCAP	1	26	2
11	1					3
17	2					4
20	1					5
84	1					6
29	2					7
100	6					8
20	1					9
			STATCAP	1	53	10
			STATCAP	2	29	11
11	1					12
20	1					13
20	1					14
60	1					15
5	1					16
90	1					17
9	1					18
30	1					19
22	1					20
8	1					21
			STATCAP	1	14	22
6	1					23
11	1					24
22	1					25
6	1					26
			STATCAP	1	9	27
20	1					28
29	2					29
84	1					30
112	1					31
40	2					32
			STATCAP	1	86	33
			STATCAP	1	22	34
			STATCAP	2	29	35
100	1					36
			STATCAP	1	29	37
75	1					38
			STATCAP	1	15	39
11	1					40

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).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	MISSISSINEWA-IN	D	138.00	13.09	
2	MODOC-IN	T	138.00	69.00	13.00
3		T	69.00	13.00	
4	MONTPELIER-IN	D	69.00	13.00	
5	MOORE PARK-MI	T	138.00	69.00	34.50
6		T	138.00	13.09	
7		T	69.00		
8	MOTTVILLE-MI	T	138.00	69.00	34.00
9		T	69.00	12.00	
10	MULLIN-IN	T	138.00	34.00	
11		T	34.50		
12	MURCH-MI	D	69.00	12.00	
13		D	69.00		
14	NEW BUFFALO-MI	D	69.00	12.00	
15	NEW CARLISLE-IN	T	138.00	34.50	
16		T	34.50	13.00	
17	NICKERSON-MI	D	138.00	13.09	
18	NILES-MI	T	69.00	34.00	
19		T	69.00	13.09	
20		T	69.00		
21	NOBLE-IN	D	69.00	13.00	
22	NORTH KENDALLVILLE-IN	D	69.00	12.00	
23	NORTH PORTLAND-IN	D	69.00	13.00	
24	NORTHLAND-IN	D	138.00	13.09	
25	NORTHWEST ELKHART-IN	D	34.50	13.00	
26		D	34.50	12.00	
27		D	34.50		
28	OHIO OIL-IN	D	34.50	2.40	
29	OLIVE-IN	T	345.00	138.00	34.50
30		T	138.00	69.00	34.00
31		T	138.00	13.09	
32	OSOLO-IN	T	138.00	69.00	34.00
33		T	138.00	13.09	
34		T	34.50		
35	OSSIAN-IN	D	69.00	13.00	
36	PARNELL-IN	D	34.50	13.09	
37		D	34.50	13.00	
38	PEARL STREET-MI	D	34.50	12.00	
39	PENDLETON-IN	T	138.00	35.00	
40		T	34.50		

SUBSTATIONS (Continued)

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.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
12	1					1
60	1					2
5	1					3
22	1					4
90	1					5
20	1					6
			STATCAP	1	16	7
90	1					8
3	1					9
30	1					10
			STATCAP	1	20	11
20	1					12
			STATCAP	1	26	13
31	2					14
30	1					15
8	1					16
20	1					17
45	1					18
20	1					19
			STATCAP	1	14	20
11	1					21
22	1					22
20	1					23
32	2					24
20	1					25
11	1					26
			STATCAP	1	14	27
6	6					28
675	1					29
27	1					30
9	1					31
75	1					32
42	2					33
			STATCAP	1	14	34
20	1					35
20	1					36
20	1					37
17	2					38
125	2					39
			STATCAP	2	47	40

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).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	PETTIT AVENUE-IN	D	34.50	13.00	
2	PIGEON RIVER-MI	D	69.00	12.00	
3	PINE ROAD-IN	D	138.00	13.09	
4	PIPE CREEK-IN	D	138.00	12.00	
5	POKAGON(MBH)-MI	T	138.00	69.00	13.00
6		T	69.00	13.00	
7		T	69.00		
8	PORTLAND (IM)-IN	D	69.00	13.00	
9	PRICE-IN	D	69.00	13.09	
10	RANDOLPH-IN	T	138.00	69.00	13.00
11		T	138.00	13.09	
12		T	69.00		
13		T	34.50	12.00	
14	REED-IN	D	138.00	13.09	
15	RIVERSIDE (IM)-MI	T	138.00	69.00	34.00
16		T	138.00	13.09	
17		T	138.00		
18	ROBISON PARK-IN	T	345.00	138.00	13.00
19		T	138.00		
20		T	138.00	70.50	36.20
21		T	138.00	13.09	
22	ROCKPORT-IN	T	765.00		
23		T	138.00		
24		T	34.50	13.00	
25	ROYERTON-IN	D	138.00	13.09	
26	SAUK TRAIL-MI	D	138.00	13.09	
27	SCHOOLCRAFT-MI	D	69.00	13.00	
28	SCOTTDALE-MI	D	34.50	13.09	
29		D	34.50	13.00	
30	SELMA PARKER-IN	T	138.00	13.09	
31	SISTER LAKES-MI	D	34.50	12.00	
32	SODUS-MI	D	138.00	13.09	
33	SORENSON-IN	T	345.00	138.00	34.00
34	SOUTH BEND-IN	T	138.00	69.00	34.00
35		T	138.00	34.00	
36		T	138.00	13.09	
37		T	138.00		
38	SOUTH BERNE-IN	D	69.00	12.00	
39	SOUTH DECATUR-IN	D	69.00	13.09	
40		D	69.00	13.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

SUBSTATIONS (Continued)

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.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
20	1					1
20	1					2
20	1					3
20	1					4
115	1					5
5	1					6
			STATCAP	1	14	7
17	2					8
20	1					9
56	1					10
22	1					11
			STATCAP	1	14	12
4	1					13
22	1					14
134	2					15
20	1					16
			STATCAP	1	106	17
672	1					18
			STATCAP	1	86	19
90	1					20
40	2					21
			REACTOR	6	300	22
			REACTOR	2	40	23
2	2	1				24
11	1					25
20	1					26
22	1					27
9	1					28
11	1					29
11	1					30
15	2					31
11	1					32
1347	2					33
130	1					34
150	2					35
20	1					36
			STATCAP	1	53	37
12	1					38
20	1					39
20	1					40

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).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	SOUTH ELWOOD-IN	T	138.00	34.00	
2		T	138.00	13.09	
3	SOUTH HAVEN-MI	T	69.00		
4	SOUTH SIDE (MARION)-IN	D	34.50	13.09	
5		D	34.50	4.00	
6	SOUTH SIDE (SOUTH BEND)-IN	D	138.00	13.09	
7	SOYA-IN	D	34.50	4.00	
8	SPRING STREET-IN	D	34.50	13.00	
9		D	34.50	12.00	
10	SPY RUN-IN	T	138.00	34.00	
11		T	138.00	13.09	
12		D	34.50		
13		D	34.50	12.00	
14		D	34.50	4.00	
15	ST. JOE-IN	D	69.00	13.09	
16	STATE STREET-IN	D	138.00	13.09	
17	STEVENSVILLE-MI	D	69.00	13.00	
18	STONE LAKE-MI	D	69.00	13.00	
19		D	69.00	12.00	
20	STUBEY ROAD-MI	D	69.00	12.00	
21		D	69.00		
22	STUDEBAKER-IN	D	138.00	13.80	
23		D	138.00	13.09	
24	SULLIVAN (IM)-IN	T	765.00		
25		T	765.00	345.00	34.50
26		T	765.00	345.00	34.00
27		T	138.00		
28	SUMMIT-IN	D	138.00	13.09	
29	SWANSON-IN	D	69.00	34.00	
30		D	69.00		
31	TANNERS CREEK-IN	T	345.00	141.00	13.20
32		T	345.00	137.50	13.14
33	THOMAS ROAD-IN	D	69.00	13.09	
34	THREE M-IN	D	69.00	4.00	
35	THREE RIVERS (FTW)-IN	D	34.50	14.40	
36		D	34.50	13.00	
37	THREE RIVERS (MBH)-MI	D	69.00	12.00	
38	TILLMAN-IN	T	138.00	36.20	
39	TILLOTSON-IN	D	34.50	13.00	
40	TRIER-IN	D	138.00	13.09	

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
30	1					1
20	1					2
			STATCAP	2	19	3
20	1					4
8	3					5
20	1					6
11	1					7
8	1					8
12	1					9
200	2					10
22	1	1				11
			STATCAP	1	10	12
20	1					13
8	1					14
20	1					15
22	1					16
19	2					17
7	1					18
9	1					19
11	1					20
			STATCAP	1	14	21
36	2					22
20	1					23
			REACTOR	3	150	24
500	1					25
2500	5	1				26
			REACTOR	1	20	27
40	2					28
45	2					29
			STATCAP	1	14	30
150	1					31
150	1					32
20	1					33
13	1					34
22	2					35
10	2					36
22	1					37
18	1					38
20	1					39
20	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	TWENTY FIRST STREET-IN	D	34.50	13.00	
2	TWENTY THIRD STREET (IM)-IN	T	138.00	69.00	34.00
3		T	34.50		
4	TWIN BRANCH 138KV-IN	T	345.00	138.00	34.50
5		T	345.00	137.50	13.20
6		T	138.00	13.09	
7	TWIN BRANCH 34KV-IN	T	34.50	13.00	
8		T	34.50		
9	UPLAND-IN	D	69.00	13.20	
10	UTICA (IM)-IN	D	34.50	13.09	
11	VALLEY-MI	T	138.00	69.00	34.00
12		T	138.00		
13		T	34.50	34.00	
14		T	34.50		
15	VAN BUREN-IN	T	138.00	69.00	13.00
16	VICKSBURG-MI	D	69.00	13.09	
17		D	69.00	12.00	
18	WABASH AVENUE-IN	D	69.00	13.09	
19	WALLEN-IN	T	138.00	69.00	34.00
20		T	138.00	13.09	
21	WAYNE TRACE-IN	D	138.00	13.09	
22	WAYNEDALE-IN	D	138.00	13.09	
23		D	138.00	12.47	
24	WEBSTER-IN	D	34.50	14.00	
25		D	34.50	12.00	
26		D	13.80		
27	WES-DEL-IN	D	138.00	13.09	
28	WEST END-IN	D	34.50	13.00	
29		D	34.50	4.00	
30	WEST SIDE-IN	T	138.00	69.00	34.00
31		T	138.00	13.09	
32		T	34.50		
33	WEST STREET-MI	D	138.00	13.09	
34	WHITAKER-IN	D	34.50	12.00	
35	WINCHESTER (IM)-IN	T	69.00	34.00	
36		T	69.00	13.00	
37		T	69.00		
38	WOODBURN-IN	D	69.00	13.00	
39	WOODS ROAD-IN	D	138.00	12.00	
40					

SUBSTATIONS (Continued)

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.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
19	2					1
213	2					2
			STATCAP	2	29	3
675	1					4
450	1					5
20	1					6
3	1					7
			STATCAP	1	14	8
20	1					9
42	2					10
75	1					11
			STATCAP	1	44	12
11		1				13
			STATCAP	1	7	14
56	1					15
20	1					16
9	1					17
20	1					18
54	1					19
20	2					20
22	1					21
22	1					22
20	1					23
19	4					24
20	1					25
			STATCAP	2	14	26
22	1					27
9	2					28
8	1					29
84	1					30
42	2					31
			STATCAP	1	12	32
20	1					33
20	1					34
17	1					35
26	2					36
			STATCAP	2	22	37
11	1					38
10	1					39
						40

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.
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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).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	88 STATIONS UNDER 10 MVA	T/D			
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					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

SUBSTATIONS (Continued)

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.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
400	101					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

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 Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Administrative and General Expenses	AEPSC	920-931	8,837,037
3	Administrative and General Expenses	OPCO	920-931	654,325
4	AEP Support Services	AEPSC	417	1,195,117
5	Assets and Other Debits - Utility Plant	OPCO	107,108	440,121
6	Audit Services	AEPSC	920	1,218,073
7	Central Machine Shop	APCO	Various	1,279,870
8	Civic and Political Activities	AEPSC	426	826,439
9	Construction Services	AEPSC	107,108	29,225,667
10	Coal Transloading	OPCO	151	32,639,336
11	Corporate Accounting	AEPSC	920	4,024,999
12	Corporate Communication	AEPSC	920	1,312,164
13	Corporate Planning and Budgeting	AEPSC	920	1,762,418
14	Customer Accounts Expense	AEPSC	901-905	12,794,480
15	Customer and Distribution Services	AEPSC	920	419,182
16	Customer Service and Informational Expenses	AEPSC	907,908,910	395,070
17	Distribution Expenses - Maintenance	AEPSC	590-597	288,387
18	Distribution Expenses - Operation	AEPSC	580-589	3,678,057
19	Emission Allowances Purchases	APCO	158	22,903,482
20	**Non-power Goods or Services Provided for Affiliate**			
21	Assets and Other Debits - Utility Plant	I&M Transmission Co	107,108	3,988,288
22	Assets and Other Debits - Utility Plant	OPCO	107,108	278,246
23	Barging	AEG	417	19,960,562
24	Barging	APCO	417	34,724,962
25	Barging	OPCO	417	37,111,608
26	Distribution Expenses - Maintenance	APCO	592-595	782,995
27	Fleet and Vehicle Charges	APCO	Various	1,162,448
28	Fuel Carbon Activation	AEG	154	4,320,461
29	Fuel Handling	AEG	152	6,833,580
30	Material and Supplies	APCO	Various	486,705
31	Material and Supplies	OPCO	Various	808,441
32	O&M Services for Rockport Plant	AEG	Various	22,391,581
33	Steam Power Generation - Maintenance	AEG	510-514	552,687
34	Steam Power Generation - Operation	AEG	500,506	4,648,591
35	Railcar Lease	PSO	151	322,047
36	Railcar Lease	SWEPCO	151	1,468,142
37	Survey Coal	AEGCO	Various	660,964
38	Administrative and General Expenses	AEP River Ops	920,921	543,014
39	Assets and Other Debits - Utility Plant	AEPSC	107	363,283
40	Barging	AEP River Ops	417	20,917,308
41	Liabilities and Other Credits - Deferred Credits	OPCO	253	362,698
42	Building and Property Leases	AEPSC	454	1,477,683

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 Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Emission Allowance Purchases	OPCO	158	4,276,097
3	Environmental Safety and Health Facilities	AEPSC	920	1,557,201
4	Factored Customer A/R Bad Debts	AEP Credit	426	3,767,198
5	Factored Customer A/R Expense	AEP Credit	426	2,353,486
6	Finance, Accounting and Strategic Planning	AEPSC	920	362,892
7	Fleet and Vehicle Charges	APCO	Various	1,284,870
8	Fuel and Storeroom Services	AEPSC	151,152,163	4,234,246
9	Human Resources	AEPSC	923	3,802,252
10	Hydraulic Power Generation - Operation	AEPSC	535,537,539	1,343,017
11	Information Technology	AEPSC	923	12,066,606
12	Legal GC/Administration	AEPSC	920	2,737,092
13	Material and Supplies	APCO	Various	529,445
14	Material and Supplies	I&M Transmission Co	107,570	914,171
15	Material and Supplies	OPCO	Various	1,716,412
16	Nuclear Power Generation - Maintenance	AEPSC	528-532	1,085,906
17	Nuclear Power Generaion - Operation	AEPSC	517,520,524	1,211,476
18	Other Power Generation - Maintenance	AEPSC	553-557	6,583,088
19	Rail Car Lease	OPCO	186	889,391
20	**Non-power Goods or Services Provided for Affiliate**			
21	Other Income and Deductions - Other Income	AEP River Ops	417	260,745
22	Assets and Other Debits - Deferred Debits	OPCO	184,186,188	2,900,041
23	Barging	Cardinal	417	4,264,320
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Indiana Michigan Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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 Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Rail Car Lease	SWEPCO	186	842,936
3	Rail Car Maintenance	OPCO	151	3,342,737
4	Rail Car Maintenance	SWEPCO	151	1,585,797
5	Real Estate and Workplace Services	AEPSC	923	1,370,730
6	Regulatory Services	AEPSC	920	2,871,847
7	Research and Other Services	AEPSC	182-188	4,411,944
8	Risk and Strategic Services	AEPSC	920	806,625
9	Steam Power Generation - Maintenance	AEPSC	510-514	2,383,397
10	Steam Power Generation - Operation	AEPSC	500,501,502,506	6,520,096
11	Supply Chain and Fleet Operations	AEPSC	923	252,589
12	Transmission Expenses - Maintenance	AEPSC	568-572	1,228,283
13	Transmission Expenses - Operation	AEPSC	560-567	4,642,227
14	Treasury and Investor Relations	AEPSC	920	739,845
15	Utility Operations	AEPSC	920	496,779
16	Barging	AEP River OPS	417	24,289,137
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20	**Non-power Goods or Services Provided for Affiliate**			
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Schedule Page: 429 Line No.: 6 Column: b

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.

Schedule Page: 429 Line No.: 7 Column: c

107,108,163,506,512,513,524,530,531,544

Schedule Page: 429 Line No.: 27 Column: b

Costs related to AEP's fleet vehicles are allocated in the same manner as the labor of each department utilizing the vehicles. To the extent a department provides service to another affiliate company, an applicable share of their fleet costs are also assigned to that affiliate company.

Schedule Page: 429 Line No.: 30 Column: c

107,108,154,512,513,514,531,570,571,588,593,597,598,903

Schedule Page: 429 Line No.: 31 Column: c

107,108,154,186,506,512,513,514,531,539,562,566,570,571,588,597,903,930,935

Schedule Page: 429.1 Line No.: 13 Column: c

107,154,163,511,512,513,514,529,544,570,571,573,586,588,592,593,594,930

Schedule Page: 429.1 Line No.: 15 Column: c

107,108,154,163,186,506,511,512,562,570,571,592,593,594,595,902,921,935