THIS FILING IS		
Item 1: [X] An Initial (Original) Submission	OR [ ]	Resubmission No. ____

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2014)

Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2014)

Form 3-Q Approved
OMB No.1902-0205
(Expires 05/31/2014)

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

Exact Legal Name of Respondent (Company)	**Year/Period of Report**
Ohio Power Company	**End of** 2012/Q4

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

GENERAL INFORMATION

I. Purpose

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

II. Who Must Submit

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

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

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

III. What and Where to Submit

(a) Submit FERC Forms 1 and 3-Q electronically through the forms submission software. Retain one copy of each report for your files. Any electronic submission must be created by using the forms submission software provided free by the Commission at its web site: http://www.ferc.gov/docs-filing/eforms/form-1/elec-subm-soft.asp. The software is used to submit the electronic filing to the Commission via the Internet.

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

(c) Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:

Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

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

The CPA Certification Statement should:

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

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

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

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

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

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases."

The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

(f) Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. To further that effort, new selections, "Annual Report to Stockholders," and "CPA Certification Statement" have been added to the dropdown "pick list" from which companies must choose when eFiling. Further instructions are found on the Commission's website at http://www.ferc.gov/help/how-to.asp.

(g) Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from http://www.ferc.gov/docs-filing/eforms/form-1/form-1.pdf and http://www.ferc.gov/docs-filing/eforms.asp#3Q-gas .

IV. When to Submit:

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

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

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

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,144 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 150 hours per response.

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

GENERAL INSTRUCTIONS

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

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

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

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

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

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

VII For any resubmissions, submit the electronic filing using the form submission software only. Please explain the reason for the resubmission in a footnote to the data field.

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

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

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

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

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

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

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

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

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

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

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

DEFINITIONS

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

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

EXCERPTS FROM THE LAW

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

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

(3) ’Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;

(4) 'Person' means an individual or a corporation;

(5) 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

(7) 'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; ......

(11) "project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

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

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

"Sec. 304. (a) Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may be rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the -proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports salt be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309. The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

General Penalties

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

FERC FORM NO. 1/3-Q:
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent Ohio Power Company	02 Year/Period of Report End of 2012/Q4
03 Previous Name and Date of Change *(if name changed during year)* / /	
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 1 Riverside Plaza, Columbus, Ohio 43215-2373	
05 Name of Contact Person Jason M. Johnson	06 Title of Contact Person Accountant
07 Address of Contact Person *(Street, City, State, Zip Code)* AEP Service Corporation, 1 Riverside Plaza, Columbus, Ohio 43215-2373	

08 Telephone of Contact Person, *Including Area Code*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(614) 716-1000	(1) [X] An Original (2) [ ] A Resubmission	/ /

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

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

01 Name / 02 Title	03 Signature	04 Date Signed *(Mo, Da, Yr)*
01 Name Andrew B. Reis 02 Title Assistant Controller	Andrew B. Reis	04/11/2013

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

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

LIST OF SCHEDULES (Electric Utility)

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

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

LIST OF SCHEDULES (Electric Utility) (continued)

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

LIST OF SCHEDULES (Electric Utility) (continued)

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

Stockholders' Reports Check appropriate box:

- [ ] Two copies will be submitted
- [ ] No annual report to stockholders is prepared

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, Ohio 43215-2373

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

Ohio - May 8, 1907
Reorganized - December 18, 1924

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

Electric - Ohio

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 the date when such independent accountant was initially engaged:
(2) [X] No

CONTROL OVER RESPONDENT

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

American Electric Power Company, Inc.

Ownership of 100% of the Common Stock.

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

CORPORATIONS CONTROLLED BY RESPONDENT

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

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Cardinal Operating Company	Operates Generating Station	50	(a)
2				
3	Central Coal Company	Coal Mining - Inactive	50	(b)
4				
5	Conesville Coal Preparation Company	Provides coal washing	100	
6		services for one of the		
7		Company's generating		
8		stations. Became inactive		
9		in 2012.		
10	(a) Joint Control			
11	- Buckeye Power, Inc.			
12	(b) Joint Control			
13	- Appalachian Power Company			
14	(Associated Company)			
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

OFFICERS

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

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	See Footnote		
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Schedule Page: 104 Line No.: 1 Column: a

Executive Compensation Table

The following table provides summary information concerning compensation paid to or accrued by us on behalf of our Chief Executive Officer, our Chief Financial Officer and the three other most highly compensated executive officers, to whom we refer collectively as the named executive officers.

Name and Principal Position (a)	Salary ($)(1) (b)	Bonus ($) (c)	Stock Awards ($)(2) (d)	Option Awards ($) (e)	Non-Equity Incentive Plan Compensation ($)(3) (f)	Change in Pension Value and Non-qualified Deferred Compensation Earnings ($)(4) (g)	All Other Compensation Earnings ($)(5) (h)	Total ($) (i)
Nicholas K. Akins — President and Chief Executive Officer	903,461	—	4,600,008	—	1,500,000	176,312	106,709	7,286,490
Brian X. Tierney — Executive Vice President and Chief Financial Officer	652,500	—	1,896,860	—	800,000	228,760	49,467	3,627,587
Robert P. Powers — Executive Vice President and Chief Operating Officer	652,500	—	1,896,860	—	800,000	586,359	60,809	3,996,528
Dennis E. Welch(6) — Executive Vice President and Chief External Officer	465,283	—	920,291	—	415,000	81,405	39,275	1,921,254
David M. Feinberg(7) — Executive Vice President and General Counsel	451,731	—	857,807	—	450,000	30,361	37,044	1,826,943

(1) Amounts in the salary column are composed of executive salaries paid for the year shown, which include 261 days of pay for 2012, which is one day more than the standard 260 calendar work days and holidays in a year.

(2) The amounts reported in this column reflect the total grant date fair value, calculated in accordance with FASB ASC Topic 718, of performance units and restricted stock units granted under our Long-Term Incentive Plan. See Note 14 to the Consolidated Financial Statements included in our Form 10-K for the year ended December 31, 2012 for a discussion of the relevant assumptions used in calculating these amounts. The restricted stock units vest over a forty month period. The value realized for the performance units, if any, will depend on the Company's performance during a three-year performance and vesting period. The potential payout can range from 0 percent to 200 percent of the target number of performance units. Therefore, the maximum amount payable for the performance units is equal to $5,520,010 for Mr. Akins, $2,276,232 for Mr. Tierney, $2,276,232 for Mr. Powers, $1,104,350 for Mr. Welch and $1,029,368 for Mr. Feinberg.

(3) The amounts shown in this column are annual incentive awards made under the Senior Officer Incentive Plan for the year shown. At the outset of each year, the HR Committee sets annual incentive targets and performance criteria that are used after year-end to determine if and the extent to which executive officers may receive annual incentive award payments under this plan.

(4) The amounts shown in this column are attributable to the increase in the actuarial values of each of the named executive officer's combined benefits under AEP's qualified and non-qualified defined benefit plans determined using interest rate and mortality assumptions consistent with those used in the Company's financial statements. No named executive officer received preferential or above-market earnings on deferred compensation. See Note 7 to the Consolidated Financial Statements included in our Form 10-K for the year ended December 31, 2012, for a discussion of the relevant assumptions.

(5) Amounts shown in the All Other Compensation column for 2012 include: (a) Company contributions to the Company's Retirement Savings Plan, (b) Company contributions to the Company's Supplemental Retirement Savings Plan, (c) perquisites and (d) for Mr. Akins, a tax gross-up associated with a reimbursement for a Company-caused tax penalty. The amounts are listed in the following table:

All Other Compensation

Type	Nicholas K. Akins	Brian X. Tierney	Robert P. Powers	Dennis E. Welch	David M. Feinberg
Retirement Savings Plan Match	11,250	11,250	11,250	11,250	11,250
Supplemental Retirement Savings Plan Match	63,000	38,217	38,250	16,846	16,356
Perquisites	28,385	-	11,309	11,179	9,438
Tax Gross-Up	4,074	-	-	-	-
Total	106,709	49,467	60,809	39,275	37,044

Perquisites provided in 2012 included: financial counseling and tax preparation, air and hotel club memberships, and, for Mr. Akins, director's accidental death insurance premium and on one occasion, personal use of Company aircraft for a death in the family. None of the individual perquisites had a value exceeding $25,000 for a named executive officer.

(6) Mr. Welch was not considered an executive officer prior to 2012.

(7) Mr. Feinberg was not considered an executive officer prior to 2012.

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

DIRECTORS

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

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1		
2	Nicholas K. Akins, Chairman of the Board	Columbus, Ohio
3	and Chief Executive Officer	
4		
5	Lisa M. Barton, Vice President	Columbus, Ohio
6		
7	David M. Feinberg, Secretary	Columbus, Ohio
8		
9	Mark C. McCullough, Vice President	Columbus, Ohio
10		
11	Robert P. Powers, Vice President	Columbus, Ohio
12		
13	Brian X. Tierney, Vice President	Columbus, Ohio
14	and Chief Financial Officer	
15		
16	Dennis E. Welch, Vice President	Columbus, Ohio
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18	Barbara D. Radous, Vice President	Columbus, Ohio
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25	Note: The Respondent does not have an Executive Committee	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

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

Does the respondent have formula rates? [X] Yes [ ] No

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

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	PJM Interconnection L.L.C. Attachment H-14	ER08-1329
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

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

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

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

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1	20120525-5106	05/25/2012	ER08-1329	AEP PJM OATT Formula Update	PJM OATT Attachment H-14
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

INFORMATION ON FORMULA RATES
Formula Rate Variances

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

Line No.	Page No(s).	Schedule	Column	Line No
1	Not Applicable			
2				
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Name of Respondent Ohio Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report / /	Year/Period of Report 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 January 6, 2012	Village of Newcomerstown, State of Ohio	Ten (10) year franchise renewal expiring on January 6, 2022	None
Renewed on January 9, 2012	Village of Rio Grande, State of Ohio	Twenty-five (25) year franchise renewal expiring on January 9, 2037	None
Renewed on May 7, 2012	Village of Fredericktown, State of Ohio	Ten (10) year franchise renewal expiring on May 7, 2022	None
Renewed on May 15, 2012	Village of Adena, State of Ohio	Ten (10) year franchise renewal expiring on May 15, 2022	None
Renewed on July 11, 2012	Village of New Concord, State of Ohio	Ten (10) year franchise renewal expiring on July 11, 2022	None
Renewed on July 18, 2012	Village of East Canton, State of Ohio	Twenty-five (25) year franchise renewal expiring on July 18, 2037	None
Renewed on September 10, 2012	Village of Sugar Grove, State of Ohio	Twenty-five (25) year franchise renewal expiring on September 10, 2037	None
Renewed on September 13, 2012	Village of Pleasantville, State of Ohio	Twenty-five (25) year franchise renewal expiring on September 13, 2037	None
Renewed on October 16, 2012	Village of Glouster, State of Ohio	Twenty-five (25) year franchise renewal expiring on October 16, 2037	None

2. None

3. None

4. None

5. None

6. None

7. None

8. Transmission Line employees represented by Local IBEW #1466-1 were provided with a 2% general wage increase effective April 1, 2012

   Newark, Zanesville employees represented by Local IBEW #1466-2 were provided with a 2% general wage increase effective April 1, 2012

   Columbus, Athens, Chillocothe employees represented by Local IBEW #1466-3 were provided with a 2% general wage increase effective April 1, 2012

   Steubenville employees represented by Local IBEW #696 were provided with a 2% general wage increase effective April 1, 2012

Cardinal Plant employees represented by UWUA Local #478 were provided with a 2% general wage increase effective June 1, 2012

Kammer Plant employees represented by UWUA Local #468 were provided with a 2% general wage increase effective June 1, 2012

Mitchell Plant employees represented by UWUA Local #492 were provided with a 2% general wage increase effective June 1, 2012

Western Ohio Region employees represented by UWUA Local #111 were provided with a 2% general wage increase effective July 1, 2012

Canton Warehouse employees represented by UWUA Local #116 were provided with a 2% general wage increase effective July 1, 2012

Canton Region employees represented by UWUA Local #116 were provided with a 2% general wage increase effective July 1, 2012

Cook Coal Terminal employees represented by UMWA Local #2463 were provided with a 3.7% general wage increase extension through 2013

Gavin Plant employees represented by UWUA Local #296 were provided with a 2% general wage increase effective October 1, 2012

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

10. None

11. Reserved

12. Not Used

13. Nicholas K. Adkins elected as Chairman of the Board effective January 1, 2012

    David M. Feinberg elected as Director and Secretary effective January 1, 2012

    Mark C. McCullough elected as Director effective January 1, 2012

    Scott N. Smith elected as Vice President effective January 26, 2012

    Anne M. Vogel resigned as Assistant Secretary effective March 13, 2012

    Joseph Hamrock resigned as President and Chief Operating Officer effective April 30, 2012

    Pablo A. Vegas elected as President and Chief Operating Officer effective May 1, 2012

    Mark A. Peifer resigned as Vice President - Generation Assets effective May 22, 2012

    Barbara D. Radous resigned as Director and 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 (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	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	15,808,576,772	15,467,009,111
3	Construction Work in Progress (107)	200-201	354,496,915	354,465,481
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		16,163,073,687	15,821,474,592
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	6,670,266,900	6,098,377,155
6	Net Utility Plant (Enter Total of line 4 less 5)		9,492,806,787	9,723,097,437
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	0	0
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	0
14	Net Utility Plant (Enter Total of lines 6 and 13)		9,492,806,787	9,723,097,437
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		27,287,566	26,902,625
19	(Less) Accum. Prov. for Depr. and Amort. (122)		10,826,797	10,839,308
20	Investments in Associated Companies (123)		430,000	430,000
21	Investment in Subsidiary Companies (123.1)	224-225	-1,804,458	-1,834,676
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	12,759,081	19,107,019
24	Other Investments (124)		120,140,432	118,505,770
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		0	0
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		48,001,526	53,578,159
31	Long-Term Portion of Derivative Assets – Hedges (176)		286,576	35,356
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		196,273,926	205,884,945
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		3,640,465	2,095,486
36	Special Deposits (132-134)		13,619,986	23,159,947
37	Working Fund (135)		0	0
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		160,797,024	144,078,351
41	Other Accounts Receivable (143)		9,356,468	11,694,341
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		5,582,752	3,571,211
43	Notes Receivable from Associated Companies (145)		106,292,693	209,222,706
44	Accounts Receivable from Assoc. Companies (146)		170,651,273	155,961,433
45	Fuel Stock (151)	227	315,658,014	252,654,805
46	Fuel Stock Expenses Undistributed (152)	227	13,182,324	10,230,746
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	160,826,749	172,582,158
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	34,328,433	49,819,987

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

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		12,759,081	19,107,019
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)		17,727,643	22,771,853
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		532	6,220,442
60	Rents Receivable (172)		2,396,749	2,354,076
61	Accrued Utility Revenues (173)		57,886,858	19,011,672
62	Miscellaneous Current and Accrued Assets (174)		4,331,981	4,461,038
63	Derivative Instrument Assets (175)		92,184,897	107,322,185
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		48,001,526	53,578,159
65	Derivative Instrument Assets - Hedges (176)		416,113	583,909
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		286,576	35,356
67	Total Current and Accrued Assets (Lines 34 through 66)		1,096,668,267	1,117,933,390
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		14,837,869	18,103,943
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	1,409,395,872	1,357,975,634
73	Prelim. Survey and Investigation Charges (Electric) (183)		1,789,166	1,972,199
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	258,247,301	256,879,178
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)		13,215,480	14,551,607
82	Accumulated Deferred Income Taxes (190)	234	497,598,964	565,661,913
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		2,195,084,652	2,215,144,474
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		12,980,833,632	13,262,060,246

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	321,201,454	321,201,454
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)		0	0
7	Other Paid-In Capital (208-211)	253	1,707,589,825	1,707,589,825
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	2,623,929,127	2,580,395,020
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	2,204,800	2,204,800
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)	-165,724,552	-197,721,635
16	Total Proprietary Capital (lines 2 through 15)		4,489,200,654	4,413,669,464
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	0	0
19	(Less) Reaquired Bonds (222)	256-257	462,500,000	418,000,000
20	Advances from Associated Companies (223)	256-257	200,000,000	200,000,000
21	Other Long-Term Debt (224)	256-257	4,130,325,000	4,280,325,000
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		7,384,697	8,177,158
24	Total Long-Term Debt (lines 18 through 23)		3,860,440,303	4,054,147,842
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		36,380,966	40,152,075
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		624,941	601,600
29	Accumulated Provision for Pensions and Benefits (228.3)		152,059,545	308,743,140
30	Accumulated Miscellaneous Operating Provisions (228.4)		5,459,665	30,444,899
31	Accumulated Provision for Rate Refunds (229)		22,577,000	20,000,000
32	Long-Term Portion of Derivative Instrument Liabilities		25,384,811	17,502,503
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		580,515	387,068
34	Asset Retirement Obligations (230)		265,026,210	237,119,843
35	Total Other Noncurrent Liabilities (lines 26 through 34)		508,093,653	654,951,128
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		276,205,657	293,642,232
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		154,247,266	186,735,942
41	Customer Deposits (235)		50,964,245	55,784,949
42	Taxes Accrued (236)	262-263	448,942,948	437,248,507
43	Interest Accrued (237)		64,279,794	68,187,886
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

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)		277,115	2,291,821
48	Miscellaneous Current and Accrued Liabilities (242)		130,325,753	117,256,555
49	Obligations Under Capital Leases-Current (243)		14,707,005	14,095,873
50	Derivative Instrument Liabilities (244)		48,216,808	51,211,394
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		25,384,811	17,502,503
52	Derivative Instrument Liabilities - Hedges (245)		1,903,605	3,239,217
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		580,515	387,068
54	Total Current and Accrued Liabilities (lines 37 through 53)		1,164,104,870	1,211,804,805
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		274,889	275,115
57	Accumulated Deferred Investment Tax Credits (255)	266-267	11,643,327	13,492,560
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	65,678,586	50,451,156
60	Other Regulatory Liabilities (254)	278	39,462,132	38,553,823
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	376,657,740	353,460,058
63	Accum. Deferred Income Taxes-Other Property (282)		1,867,120,302	1,781,887,359
64	Accum. Deferred Income Taxes-Other (283)		598,157,176	689,366,936
65	Total Deferred Credits (lines 56 through 64)		2,958,994,152	2,927,487,007
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		12,980,833,632	13,262,060,246

Name of Respondent Ohio 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

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	4,921,622,058	5,455,769,264		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	2,721,314,561	3,210,008,620		
5	Maintenance Expenses (402)	320-323	319,324,438	393,943,466		
6	Depreciation Expense (403)	336-337	459,584,807	484,298,323		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	12,055,617	8,849,303		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	24,200,887	22,975,714		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	12,696	12,696		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		15,728,448	29,239,772		
13	(Less) Regulatory Credits (407.4)		512,603			
14	Taxes Other Than Income Taxes (408.1)	262-263	404,969,760	398,494,481		
15	Income Taxes - Federal (409.1)	262-263	91,930,521	168,987,812		
16	- Other (409.1)	262-263	8,580,447	4,537,706		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	540,713,172	596,165,325		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	395,675,882	542,311,812		
19	Investment Tax Credit Adj. - Net (411.4)	266	-1,768,489	-2,093,303		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)			8,727,304		
22	(Less) Gains from Disposition of Allowances (411.8)		8,154,591	13,979,215		
23	Losses from Disposition of Allowances (411.9)		2,117,874	5,969,272		
24	Accretion Expense (411.10)		14,767,942	13,171,145		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		4,209,189,605	4,786,996,609		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		712,432,453	668,772,655		

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
4,921,622,058	5,455,769,264					2
						3
2,721,314,561	3,210,008,620					4
319,324,438	393,943,466					5
459,584,807	484,298,323					6
12,055,617	8,849,303					7
24,200,887	22,975,714					8
12,696	12,696					9
						10
						11
15,728,448	29,239,772					12
512,603						13
404,969,760	398,494,481					14
91,930,521	168,987,812					15
8,580,447	4,537,706					16
540,713,172	596,165,325					17
395,675,882	542,311,812					18
-1,768,489	-2,093,303					19
						20
	8,727,304					21
8,154,591	13,979,215					22
2,117,874	5,969,272					23
14,767,942	13,171,145					24
4,209,189,605	4,786,996,609					25
712,432,453	668,772,655					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)		712,432,453	668,772,655		
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)		49,122,115	41,556,402		
34	(Less) Expenses of Nonutility Operations (417.1)		49,660,842	41,635,082		
35	Nonoperating Rental Income (418)		595,942	706,828		
36	Equity in Earnings of Subsidiary Companies (418.1)	119		70,000		
37	Interest and Dividend Income (419)		3,499,402	7,043,815		
38	Allowance for Other Funds Used During Construction (419.1)		3,491,759	5,548,812		
39	Miscellaneous Nonoperating Income (421)		24,890,606	55,080,024		
40	Gain on Disposition of Property (421.1)		1,511,119	11,367,656		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		33,450,101	79,738,455		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		-258,848	217,428		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		4,372,607	12,359,721		
46	Life Insurance (426.2)					
47	Penalties (426.3)		52,209	3,389,293		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		2,687,777	3,823,366		
49	Other Deductions (426.5)		280,656,471	52,563,840		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		287,510,216	72,353,648		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	1,005,527	984,577		
53	Income Taxes-Federal (409.2)	262-263	1,023,944	-76,076,084		
54	Income Taxes-Other (409.2)	262-263	87,190	-2,297,265		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	22,101,985	172,026,654		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	122,394,298	104,757,181		
57	Investment Tax Credit Adj.-Net (411.5)		-80,744	-286,702		
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-98,256,396	-10,406,001		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		-155,803,719	17,790,808		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		202,006,228	204,509,827		
63	Amort. of Debt Disc. and Expense (428)		3,978,647	4,329,899		
64	Amortization of Loss on Reaquired Debt (428.1)		1,336,128	1,338,011		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)		11,071,815	10,512,117		
68	Other Interest Expense (431)		3,747,937	3,231,163		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		9,046,128	2,349,893		
70	Net Interest Charges (Total of lines 62 thru 69)		213,094,627	221,571,124		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		343,534,107	464,992,339		
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)		343,534,107	464,992,339		

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		2,576,018,934	2,762,444,406
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	Capital Stock Expense	210		(323,317)
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			(323,317)
16	Balance Transferred from Income (Account 433 less Account 418.1)		343,534,107	464,922,339
17	Appropriations of Retained Earnings (Acct. 436)			
18	Excess Earnings on Hydro Licensed Projects	215.1	-654,657	(353,926)
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-654,657	(353,926)
23	Dividends Declared-Preferred Stock (Account 437)			
24	Perferred Stock Not Subject to Mandatory Redemption			
25	4.08% Series			(54,177)
26	4.20% Series			(87,872)
27	4.40% Series			(126,977)
28	4.50% Series			(401,542)
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			(670,568)
30	Dividends Declared-Common Stock (Account 438)			
31	Common Stock		-300,000,000	(650,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-300,000,000	(650,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		2,618,898,384	2,576,018,934
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

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)
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)		5,030,743	4,376,086
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		5,030,743	4,376,086
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		2,623,929,127	2,580,395,020
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		2,204,800	2,134,800
50	Equity in Earnings for Year (Credit) (Account 418.1)			70,000
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)		2,204,800	2,204,800

Name of Respondent Ohio 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 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)	343,534,107	464,992,339
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	495,854,007	516,136,036
5	Amortization of Regulatory Debits and Credits (Net)	15,215,845	29,239,772
6	Impairment of Long-Lived Assets	287,030,792	89,823,886
7	Carrying Costs	-16,941,933	-53,345,160
8	Deferred Income Taxes (Net)	44,744,977	121,122,986
9	Investment Tax Credit Adjustment (Net)	-1,849,233	-2,380,005
10	Net (Increase) Decrease in Receivables	-21,613,572	73,088,052
11	Net (Increase) Decrease in Inventory	-66,928,853	51,521,509
12	Net (Increase) Decrease in Allowances Inventory	15,491,554	25,322,120
13	Net Increase (Decrease) in Payables and Accrued Expenses	-30,346,942	12,870,137
14	Net (Increase) Decrease in Other Regulatory Assets	-96,646,358	-64,417,950
15	Net Increase (Decrease) in Other Regulatory Liabilities	-13,088,606	18,376,655
16	(Less) Allowance for Other Funds Used During Construction	3,491,759	5,548,812
17	(Less) Undistributed Earnings from Subsidiary Companies		70,000
18	Other (provide details in footnote):	-19,073,495	81,308,852
19	Pension Contributions to Qualified Plan Trust	-42,485,000	-127,481,000
20	Over/Under Recovered Fuel, Net	10,597,928	-727,950
21	Deferred Property Taxes	-3,848,589	-5,722,132
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	896,154,870	1,224,109,335
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-516,720,156	-459,600,015
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	-4,515,702	-822,250
30	(Less) Allowance for Other Funds Used During Construction	-3,491,759	-5,548,812
31	Other (provide details in footnote):		
32			
33	Acquired Assets	-2,919,185	-2,220,199
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-520,663,284	-457,093,652
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	7,320,163	47,462,642
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)		
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	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	45	623
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	gridSmart Reimbursement Allocation	10,013,254	25,563,591
54	(Increase) Decrease in Other Special Deposits		3,450,132
55	Notes Receivable from Associated Companies	102,930,013	-58,982,177
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-400,399,809	-439,598,841
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		50,000,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65	Long Term Issuances Costs		-252,103
66	Net Increase in Short-Term Debt (c)		
67	Proceeds from Acquired Assets subject to Capital Lease	289,918	666,647
68	Amortization of Amended Coal Contract Deferred Revenues		-276,694
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	289,918	50,137,850
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-194,500,000	-165,000,000
74	Preferred Stock		-17,831,070
75	Common Stock		
76	Other (provide details in footnote):		
77			
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock		-670,568
81	Dividends on Common Stock	-300,000,000	-650,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-494,210,082	-783,363,788
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	1,544,979	1,146,706
87			
88	Cash and Cash Equivalents at Beginning of Period	2,095,486	948,780
89			
90	Cash and Cash Equivalents at End of period	3,640,465	2,095,486

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

	2012 Cash Flow Incr/(Decr)	2011 Cash Flow Incr/(Decr)
Utility Plant, Net	$ (22,794,477)	$ (23,766,011)
Property and Investments, Net	(881,926)	(116,365)
Margin Deposits	9,539,961	10,597,708
Mark-to-Market of Risk Management Contracts	12,142,703	(3,695,224)
Prepayments	17,530,235	18,548,401
Accrued Utility Revenues, Net	(38,875,185)	41,737,804
Miscellaneous Current and Accr Assets	(3,008,336)	6,042,937
Unamortized Debt Expense	3,266,074	4,071,236
Other Deferred Debits, Net	4,675,569	(12,763,439)
Other Comprehensive Income, Net	(1,690,918)	(614,881)
Unamortized Discount/Premium on Long-Term Debt	792,461	795,867
Accumulated Provisions - Misc	(20,532,736)	43,799,732
Current and Accrued Liabilities, Net	7,098,764	(34,539,182)
Other Deferred Credits, Net	13,664,316	31,210,269
Total	**$ (19,073,495)**	**$ 81,308,852**

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

	2012 Cash Flow Incr/(Decr)	2011 Cash Flow Incr/(Decr)
Sale of H-frame Structures to Kentucky Power Company	$ 326,276	$ -
Sale of Boiler Feedpump to AEP Lawrenceburg	345,510	-
Sale of Carrier Blades to Appalachain Power Company	281,558	-
Sale of Land to Cyprus Creek Land Company	-	16,922,657
Sale of Land to Umang V. & Tracy L. Nanda	2,002,691	-
Sale of M/V Mike Weisend Towboat to Mass Mutual Life Ins. Co.	-	16,373,933
Sale of meters & transformers to various associated companies	1,062,574	3,388,604
Sale of Rotors to Appalachain Power Company	1,061,996	-
Ssle of Scrap Materials to Aaron Equipment Company	200,000	-
Sale of Scrap Metals to J.V. Metals LLC	563,000	100,760
Sale of Scrap Metals to TCI of Alabama LLC	391,572	-
Sale of Transformer (UTC 420786) to Southwestern Electric Power Co.	529,214	-
Sale of Transmission Assets to AEP Ohio Transco	555,772	8,723,440
Proceeds from acquired assets subject to operating lease	-	1,953,248
Total	**$ 7,320,163**	**$ 47,462,642**

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.

PAGE 122 INTENTIONALLY LEFT BLANK
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.
AEPGenCo	AEP Generation Resources Inc., a nonregulated AEP subsidiary in the Generation and Marketing segment.
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.
CRES	Competitive Retail Electric Service.
CSPCo	Columbus Southern Power Company, a former AEP electric utility subsidiary that was merged into OPCo effective December 31, 2011.
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.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company.
ESP	Electric Security Plans, filed with the PUCO, pursuant to the Ohio Amendments.
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.
IEU	Industrial Energy Users-Ohio.

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
IGCC	Integrated Gasification Combined Cycle, technology that turns coal into a cleaner-burning gas.
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.
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.
kV	Kilovolt.
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.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatthour.
NO_x	Nitrogen oxide.
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.
POLR	Provider of Last Resort revenues.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	Public Utilities Commission of Ohio.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
SEET	Significantly Excessive Earnings Test.
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.
SO_2	Sulfur dioxide.
SPP	Southwest Power Pool regional transmission organization.
SSO	Standard service offer.
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, OPCo engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 1,459,000 retail customers in the northwestern, central, eastern and southern sections of Ohio.

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, added KGPCo and WPCo as parties to the agreement and changed the allocation method.

In 2007, OPCo and AEGCo entered into a 10-year unit power agreement for the entire output from the Lawrenceburg Plant with an option for an additional 2-year period. OPCo pays AEGCo for the capacity, depreciation, fuel, operation, maintenance and tax expenses. These payments are due regardless of whether the plant operates.

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 OPCo's behalf. OPCo 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. OPCo 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 of 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.

OPCo 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

OPCo 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. OPCo's rates are regulated by the FERC and the PUCO. 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 PUCO also regulates certain intercompany transactions under various orders and affiliate statutes. Both the FERC and the PUCO 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. OPCo's wholesale power transactions are generally market-based. Wholesale power transactions are cost-based regulated when OPCo negotiates and files a cost-based contract with the FERC or the FERC determines that OPCo has "market power" in the region where the transaction occurs. OPCo 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 PUCO regulates all of the retail distribution operations and rates on a cost basis. The ESP rates in Ohio continue the process of aligning generation/power supply rates over time with market rates.

The FERC also regulates OPCo's wholesale transmission operations and rates. The FERC claims jurisdiction over retail transmission rates when retail rates are unbundled in connection with restructuring. OPCo's retail transmission rates in Ohio are unbundled and are based on formula rates included in the PJM OATT that are cost-based.

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 companies 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

OPCo's accounting is subject to the requirements of the PUCO 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 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 reporting of acquired generating facilities on a gross basis rather than a net basis.
- 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 an accrued provision for potential refund as other noncurrent liability rather than a current liability.
- The classification of regulatory assets and liabilities related to the accounting guidance for "Accounting for Income Taxes" as separate assets and liabilities rather than as a single amount.
- The presentation of 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 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 a capital reserve associated with gridSMART® demonstration program as other deferred credits instead of property, plant and equipment – electric distribution.
- The classification of coal procurement sales as a reduction of fuel expense rather than as revenue.
- The classification of interest receivable and interest accrued related to federal income tax and state income tax balances as separate current assets and current liabilities rather than as a single net amount.
- The classification of accumulated depreciation associated with the acquisition of JMG as miscellaneous paid-in capital and accumulated deferred income taxes rather than as accumulated depreciation.
- 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 impaired plant in service in accumulated provision for depreciation, amortization and depletion rather than in property, plant and equipment – electric generation.
- 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, OPCo'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," OPCo 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 their recovery through regulated revenues and by matching income with its passage to customers in cost-based regulated rates. Due to the passage of legislation requiring restructuring and a transition to customer choice and market-based rates, OPCo applies "Regulated Operations" accounting treatment only to specifically approved portions of its generation business consisting of fuel and capacity costs.

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 for:		
Interest (Net of Capitalized Amounts)	$ 212,770	$ 226,712
Income Taxes (Net of Refunds)	69,160	80,098
Noncash Acquisitions Under Capital Leases	8,598	5,766
As of December 31,		
Government Grants Included in Other Accounts Receivable	660	1,383
Construction Expenditures Included in Current and Accrued Liabilities	84,320	61,428

Special Deposits

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

Inventory

Fossil fuel and 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, OPCo accrues and recognizes, as Accrued Utility Revenues on the balance sheets, an estimate of the revenues for energy delivered since the last billing.

AEP Credit factors accounts receivable on a daily basis, excluding receivables from risk management activities, through purchase agreements with OPCo. See “Sale of Receivables – AEP Credit” section of Note 12 for additional information.

Allowance for Uncollectible Accounts

Generally, AEP Credit records bad debt expense related to receivables purchased from OPCo 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

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

OPCo 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

OPCo records emission allowances at cost through December 31, 2014, including the annual SO_2 and NO_X emission allowance entitlements received at no cost from the Federal EPA. OPCo records allowances expected to be consumed subsequent to December 31, 2014 at the lower of cost or market when allowances are no longer included in the FAC due to energy auctions of SSO load. Allowances are consumed in the production of energy and are recorded in Operation Expenses at an average cost. Allowances held for speculation are included in Other Investments. Gains or losses on sales of emission allowances held speculatively are recorded in Miscellaneous Nonoperating Income and Other Deductions, respectively. The purchases and sales of allowances are reported in the Operating Activities section of the statements of cash flows except speculative allowance transactions, which are reported in Investing Activities.

Property, Plant and Equipment

Regulated

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.”

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.

Nonregulated

The generation operations of OPCo generally follow the policies of rate-regulated operations listed above but with the following exceptions. Property, plant and equipment of nonregulated operations are stated at fair value at acquisition (or as adjusted for any applicable impairments) plus the original cost of property acquired or constructed since the acquisition, less disposals. Normal and routine retirements from the plant accounts, net of salvage, are charged to accumulated depreciation for most nonregulated operations under the group composite method of depreciation. A gain or loss would be recorded if the retirement is not considered an interim routine replacement. Removal costs are charged to expense.

Investment in Subsidiary Companies

OPCo has one wholly-owned subsidiary, Conesville Coal Preparation Company (CCPC). CCPC provides coal washing services for one of OPCo's generating stations. Coal washing services provided by CCPC are priced at cost plus an approved return on investment. Investment in the net assets of the wholly-owned subsidiary is carried at cost plus equity in its undistributed earnings since acquisition.

In addition, OPCo has a 50% interest in two jointly owned companies. The investments are included in Investment in Subsidiary Companies and were $735 thousand as of both December 31, 2012 and 2011. One company is a joint-facility company that operates the Cardinal Plant. The second company, Central Coal Company, which is owned with an affiliated company, is inactive. The expenses of the active joint-facility company, including compensation for the use of certain capital, are apportioned between the owners of the plant. OPCo's share of the costs is appropriately classified in operating expense accounts.

Allowance for Funds Used During Construction (AFUDC) and Interest Capitalization

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. For nonregulated operations, including generating assets owned by OPCo, interest is capitalized during construction in accordance with the accounting guidance for "Capitalization of Interest."

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.

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 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 trust and Special Deposits 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. OPCo's 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 PUCO's review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of the PUCO. On a routine basis, the PUCO reviews and/or audits OPCo's fuel procurement policies and practices, the fuel cost calculations and FAC deferrals. When a fuel cost disallowance becomes probable, OPCo adjusts its FAC deferrals and record provisions for estimated refunds to recognize these probable outcomes.

Changes in fuel costs (beginning in 2012 through the ESP related to non-auction standard service offer load served) are reflected in rates in a timely manner generally through the FAC. Changes in fuel costs, including purchased power in Ohio (beginning in 2009 through 2011) are reflected in rates through FAC phase-in plans. The FAC generally includes some sharing of off-system sales. None of the profits from off-system sales are given to customers through the FAC in Ohio.

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, OPCo records them as assets on the balance sheets. OPCo 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, OPCo writes off that regulatory asset as a charge against income.

Electricity Supply and Delivery Activities

OPCo recognizes revenues from retail and wholesale electricity sales and electricity transmission and distribution delivery services. OPCo recognizes the revenues on the statements of income upon delivery of the energy to the customer and includes 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, OPCo records expenses when purchased electricity is received and when expenses are incurred. For certain power purchase contracts that are derivatives and accounted for using MTM accounting, OPCo records these contracts on a net basis in revenues.

Energy Marketing and Risk Management Activities

AEPSC, on behalf of OPCo, 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.

OPCo recognizes revenues and expenses from wholesale marketing and risk management transactions that are not derivatives upon delivery of the commodity. OPCo 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. OPCo includes realized gains and losses on wholesale marketing and risk management transactions in revenues on a net basis. Unrealized gains and losses on wholesale marketing and risk management transactions that are accounted for using MTM are included in revenues on a net basis.

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). OPCo 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, OPCo 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. The ineffective portion of the gain or loss is recognized in revenues or expense on the income statements immediately. See "Accounting for Cash Flow Hedging Strategies" section of Note 8.

Maintenance

OPCo expenses maintenance costs as incurred. If it becomes probable that OPCo 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

OPCo 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.

OPCo accounts for uncertain tax positions in accordance with the accounting guidance for “Income Taxes.” OPCo 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 an agent for some state and local governments, OPCo collects from customers certain excise taxes levied by those state or local governments on customers. OPCo does not record these taxes as revenue or expense.

Government Grants

For OPCo’s gridSMART® demonstration program, OPCo is reimbursed by the Department of Energy for allowable costs incurred during the billing period. In addition, AEP built a cyber security operations center that will be used to enhance the capabilities for identifying cyber risks or threats, which was also partially funded by the gridSMART® demonstration grant for OPCo’s incurred costs. These reimbursements result in the reduction of Operation Expenses and Maintenance Expenses or a reduction in Construction Work in Progress.

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. OPCo’s generating operations require that these costs be expensed upon reacquisition. OPCo reports gains and losses on the reacquisition of debt for operations that are not subject to cost-based rate regulation in Amortization of Debt Discount and Expense.

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. 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.

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.

OPCo Revised Depreciation Rates

Effective December 1, 2011, OPCo revised book depreciation rates for certain generating plants consistent with shortened depreciable lives for the generating units. This change in depreciable lives resulted in a $52 million increase in depreciation expense in 2012.

In the fourth quarter of 2012, OPCo impaired the generating units discussed above (see Note 5). As a result of this impairment of the full book value of these assets, OPCo ceased depreciation on these generating units effective December 1, 2012.

2. RATE MATTERS

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

Ohio Electric Security Plan Filing

2009 – 2011 ESP

The PUCO issued an order in March 2009 that modified and approved the ESP which established rates at the start of the April 2009 billing cycle through 2011. OPCo collected the 2009 annualized revenue increase over the last nine months of 2009. The order also provided a phase-in FAC, which was authorized to be recovered through a non-bypassable surcharge over the period 2012 through 2018. The PUCO's March 2009 order was appealed to the Supreme Court of Ohio, which issued an opinion and remanded certain issues back to the PUCO.

In October 2011, the PUCO issued an order in the remand proceeding. As a result, OPCo ceased collection of POLR billings in November 2011 and recorded a write-off in 2011 related to POLR collections for the period June 2011 through October 2011. In February 2012, the Ohio Consumers' Counsel and the IEU filed appeals of that order with the Supreme Court of Ohio challenging various issues, including the PUCO's refusal to order retrospective relief concerning the POLR charges collected during 2009 – 2011 and various aspects of the approved environmental carrying charge, which, if ordered, could reduce OPCo's net deferred fuel costs up to the total balance. As of December 31, 2012, OPCo's net deferred fuel balance was $519 million, excluding unrecognized equity carrying costs. A decision from the Supreme Court of Ohio is pending.

In January 2011, the PUCO issued an order on the 2009 SEET filing, which resulted in a write-off in 2010 and a subsequent refund to customers during 2011. The IEU and the Ohio Energy Group filed appeals with the Supreme Court of Ohio challenging the PUCO's SEET decision. In December 2012, the Supreme Court of Ohio issued an order which rejected all of the intervenors' challenges and affirmed the PUCO decision.

The 2009 SEET order gave consideration for a future commitment to invest $20 million to support the development of a large solar farm. In January 2013, the PUCO found there was not a need for the large solar farm. The PUCO noted that OPCo remains obligated to spend $20 million on this solar project or another similar project by the end of 2013.

In July 2011, OPCo filed its 2010 SEET filing with the PUCO based upon the approach in the PUCO's 2009 order. Subsequent testimony and legal briefs from intervenors recommended a refund of up to $62 million of 2010 earnings, which included off-system sales in the SEET calculation. In December 2011, the PUCO staff filed testimony that recommended a $23 million refund of 2010 earnings. OPCo provided a reserve based upon management's estimate of the probable amount for a PUCO ordered SEET refund. OPCo is required to file its 2011 SEET filing with the PUCO on a separate CSPCo and OPCo company basis. The PUCO approved OPCo's request to file the 2011 SEET one month after the PUCO issues an order on the 2010 SEET. Management does not currently believe that there were significantly excessive earnings in 2011 for either CSPCo or OPCo and in 2012 for OPCo.

Management is unable to predict the outcome of the unresolved litigation discussed above. If these proceedings result in adverse rulings, it could reduce future net income and cash flows and impact financial condition.

January 2012 – May 2016 ESP as Rejected by the PUCO

In December 2011, the PUCO approved an ESP modified stipulation which established a SSO pricing for generation. Various parties filed for rehearing with the PUCO requesting that the PUCO reconsider adoption of the modified stipulation. In February 2012, the PUCO issued an entry on rehearing which rejected the modified stipulation and ordered a return to the 2011 ESP rates. Those rates remained in effect until the new ESP was approved in August 2012. See the "June 2012 – May 2015 ESP Including Capacity Charge" section below.

As a result of the PUCO's rejection of the modified stipulation, OPCo reversed a $35 million obligation to contribute to the Partnership with Ohio and the Ohio Growth Fund and an $8 million regulatory asset for 2011 storm damage, both originally recorded in 2011.

As directed by the February 2012 order, OPCo filed revised tariffs with the PUCO to implement the provisions of the 2011 ESP. Included in the revised tariffs was the Phase-In Recovery Rider (PIRR) to recover deferred fuel costs as authorized under the 2009 – 2011 ESP order. In March 2012, the PUCO issued an order that directed OPCo to file new revised tariffs removing the PIRR and stated that its recovery would be addressed in a future proceeding. OPCo implemented the new revised tariffs in March 2012. In March 2012, OPCo resumed recording a weighted average cost of capital return on the deferred fuel balance in accordance with the 2009 - 2011 ESP order. OPCo also filed a request for rehearing of the March 2012 order relating to the PIRR, which the PUCO denied but provided that all of the substantive concerns and issues raised would be addressed in a separate PIRR docket.

In August 2012, the PUCO ordered implementation of PIRR rates beginning September 2012. The PUCO ruled that carrying charges should be calculated without an offset for accumulated deferred income taxes and that a long-term debt rate should be applied when collections begin. The August 2012 order was upheld on rehearing by the PUCO in October 2012. In November 2012, OPCo filed an appeal at the Supreme Court of Ohio claiming a long-term debt rate modified the previously adjudicated ESP order, which granted a weighted average cost of capital rate. The IEU and the Ohio Consumers' Counsel also filed appeals at the Supreme Court of Ohio in November 2012 arguing that the PUCO should have reduced the deferred fuel balance to reflect the prior "improper" collection of POLR revenues and reduced carrying costs due to an accumulated deferred income tax credit. See the "2009 – 2011 ESP" section above. These appeals could reduce OPCo's net deferred fuel balance up to the total balance, which would reduce future net income and cash flows. A decision from the Supreme Court of Ohio is pending.

June 2012 – May 2015 ESP Including Capacity Charge

In August 2012, the PUCO issued an order which adopted and modified a new ESP that establishes base generation rates through May 2015, adopted a 12% earnings threshold for the SEET and allowed the continuation of the fuel adjustment clause. Further, the ESP established a non-bypassable Distribution Investment Rider effective September 2012 through May 2015 to recover, with certain caps, post-August 2010 distribution investment. The ESP also maintained recovery of several previous ESP riders and required OPCo to contribute $2 million per year during the ESP to the Ohio Growth Fund. In addition, the PUCO approved a storm damage recovery mechanism.

As part of the ESP decision, the PUCO ordered OPCo to conduct an energy-only auction for 10% of the SSO load with delivery beginning six months after the receipt of final orders in both the ESP and corporate separation cases and extending through May 2015. The PUCO also ordered OPCo to conduct energy-only auctions for an additional 50% of the SSO load with delivery beginning June 2014 through May 2015 and for the remaining 40% of the SSO load for delivery from January 2015 through May 2015. OPCo will conduct energy and capacity auctions for its entire SSO load for delivery starting in June 2015.

In July 2012, the PUCO issued an order in a separate capacity proceeding which stated that OPCo must charge CRES providers the Reliability Pricing Model (RPM) price and authorized OPCo to defer a portion of its incurred capacity costs not recovered from CRES providers up to $188.88/MW day. The RPM price is approximately $20/MW day through May 2013. In December 2012, various parties filed notices of appeal of the capacity costs decision with the Supreme Court of Ohio.

As part of the August 2012 PUCO ESP order, the PUCO established a non-bypassable Retail Stability Rider (RSR), effective September 2012. The RSR is intended to provide approximately $500 million over the ESP period and will be collected from customers at $3.50/MWh through May 2014 and $4.00/MWh for the period June 2014 through May 2015, with $1.00/MWh applied to the deferred capacity costs. As of December 31, 2012, OPCo recorded $66 million of incurred deferred capacity costs, including debt carrying costs, in Regulatory Assets on the balance sheet. In August 2012, the IEU filed an action with the Supreme Court of Ohio stating, among other things, that OPCo's collection of its capacity costs is illegal. In September 2012, OPCo and the PUCO filed motions to dismiss the IEU's action. If OPCo is ultimately not permitted to fully collect its deferred capacity costs, it would reduce future net income and cash flows and impact financial condition. A decision from the Supreme Court of Ohio is pending.

In January 2013, the PUCO issued its Order on Rehearing for the ESP which generally upheld its August 2012 order including the implementation of the RSR. The PUCO clarified that a final reconciliation of revenues and costs would be permitted for any over- or under-recovery on several riders including fuel. In addition, the PUCO addressed certain issues around the energy auctions while other SSO issues related to the energy auctions were deferred to a separate docket. If OPCo is ultimately not permitted to fully collect its ESP rates, including the RSR, it would reduce future net income and cash flows and impact financial condition.

Corporate Separation

In October 2012, the PUCO issued an order which approved the corporate separation of OPCo's generation assets including the transfer of OPCo's generation assets at net book value to AEPGenCo. AEPGenCo will also assume the associated generation liabilities. In December 2012, the PUCO granted the IEU and Ohio Consumers' Counsel requests for rehearing for the purpose of further consideration and those requests remain pending.

Also in October 2012, filings at the FERC were submitted related to corporate separation. See the "Corporate Separation and Termination of Interconnection Agreement" section below.

2011 Ohio Distribution Base Rate Case

In December 2011, the PUCO approved a stipulation which provided for no change in distribution rates and a new rider for a $15 million annual credit to residential ratepayers due principally to the inclusion of the rate base distribution investment in the Distribution Investment Rider (DIR) as approved in December 2011 by the modified stipulation in the ESP proceeding. However, when the February 2012 PUCO order rejected the ESP modified stipulation, collection of the DIR terminated. In August 2012, the PUCO approved a new DIR as part of the June 2012 – May 2015 ESP proceeding. The DIR is capped at $86 million in 2012, $104 million in 2013, $124 million in 2014 and $52 million for the period January through May 2015, for a total of $366 million.

Storm Damage Recovery Rider (SDRR)

In December 2012, OPCo submitted an application with the PUCO to establish initial SDRR rates. The SDRR seeks recovery of 2012 incremental storm distribution expenses over twelve months starting with the effective date of the SDRR as approved by the PUCO. If the PUCO extends recovery beyond twelve months and/or does not commence cost recovery by April 2013, OPCo requested approval of a weighted average cost of capital carrying charge, effective April 2013. As of December 31, 2012, OPCo recorded $62 million in Regulatory Assets on the balance sheet related to 2012 storm damage. If OPCo is not ultimately permitted to recover these storm costs, it would reduce future net income and cash flows and impact financial condition.

2009 Fuel Adjustment Clause Audit

The PUCO selected an outside consultant to conduct an audit of OPCo's FAC for 2009. The outside consultant provided its audit report to the PUCO. In January 2012, the PUCO ordered that the remaining $65 million in proceeds from a 2008 coal contract settlement agreement be applied against OPCo's under-recovered fuel balance. In April 2012, on rehearing, the PUCO ordered that the settlement credit only needed to reflect the Ohio retail jurisdictional share of the gain not already flowed through the FAC with carrying charges. OPCo recorded a $30 million net favorable adjustment on the statement of income in the second quarter of 2012. The January 2012 PUCO order also stated that a consultant should be hired to review the coal reserve valuation and recommend whether any additional value should benefit ratepayers. Management is unable to predict the outcome of any future consultant recommendation. If the PUCO ultimately determines that additional amounts should benefit ratepayers as a result of the consultant's review of the coal reserve valuation, it could reduce future net income and cash flows and impact financial condition.

In August 2012, intervenors filed with the Supreme Court of Ohio claiming the settlement credit ordered by the PUCO should have reflected the remaining gain not already flowed through the FAC with carrying charges, which, if ordered, would be $35 million plus carrying charges. If the Supreme Court of Ohio ultimately determines that additional amounts should benefit ratepayers, it could reduce future net income and cash flows and impact financial condition.

2010 and 2011 Fuel Adjustment Clause Audits

The PUCO-selected outside consultant issued its 2010 and 2011 FAC audit reports which included a recommendation that the PUCO reexamine the carrying costs on the deferred FAC balance and determine whether the carrying costs on the balance should be net of accumulated income taxes. As of December 31, 2012, the amount of OPCo's carrying costs that could potentially be reduced due to the accumulated income tax issue is estimated to be approximately $36 million, including $19 million of unrecognized equity carrying costs. These amounts include the carrying costs exposure of the 2009 FAC audit, which has been appealed by an intervenor to the Supreme Court of Ohio. Decisions from the PUCO are pending. Management is unable to predict the outcome of these proceedings. If the PUCO orders result in a reduction to the FAC deferral, it would reduce future net income and cash flows and impact financial condition.

Ormet Interim Arrangement

OPCo and Ormet, a large aluminum company, filed an application with the PUCO for approval of an interim arrangement governing the provision of generation service to Ormet. This interim arrangement was approved by the PUCO and was effective from January 2009 through September 2009. In March 2009, the PUCO approved a FAC in the ESP filing and the FAC aspect of the ESP order was upheld by the Supreme Court of Ohio. The approval of the FAC as part of the ESP, together with the PUCO approval of the interim arrangement, provided the basis to record a regulatory asset for the difference between the approved market price and the rate paid by Ormet. Through September 2009, the last month of the interim arrangement, OPCo had $64 million of deferred FAC costs related to the interim arrangement, excluding $2 million of unrecognized equity carrying costs. In November 2009, OPCo requested that the PUCO approve recovery of the deferral under the interim agreement plus a weighted average cost of capital carrying charge. The deferral amount is included in OPCo's FAC phase-in deferral balance. In the 2009 – 2011 ESP proceeding, intervenors requested that OPCo be required to refund the Ormet-related regulatory asset and requested that the PUCO prevent OPCo from collecting the Ormet-related revenues in the future. The PUCO did not take any action on this request. The intervenors raised the issue again in response to OPCo's November 2009 filing to approve recovery of the deferral under the interim agreement. This issue remains pending before the PUCO. If OPCo is not ultimately permitted to fully recover its requested deferrals under the interim arrangement, it would reduce future net income and cash flows and impact financial condition.

Special Rate Mechanism for Ormet

In October 2012, the PUCO issued an order approving a delayed payment plan for Ormet of its October and November 2012 power billings totaling $27 million to be paid in equal monthly installment over the period January 2014 to May 2015 without interest. In the event Ormet does not pay the $27 million, the PUCO permitted OPCo to recover the unpaid balance, up to $20 million, in the economic development rider. To the extent unpaid amounts exceed $20 million, it will reduce future net income and cash flows.

Ohio IGCC Plant

In March 2005, OPCo filed an application with the PUCO seeking authority to recover costs of building and operating an IGCC power plant. As of December 31, 2012, OPCo has collected $24 million in pre-construction costs authorized in a June 2006 PUCO order. Intervenors have filed motions with the PUCO requesting all collected pre-construction costs be refunded to Ohio ratepayers with interest.

Management cannot predict the outcome of these proceedings concerning the Ohio IGCC plant or what effect, if any, these proceedings would have on future net income and cash flows. However, if OPCo is required to refund pre-construction costs collected, it could reduce future net income and cash flows and impact financial condition.

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. OPCo's portion of recognized gross SECA revenues is $92.1 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.

Corporate Separation and Termination of Interconnection Agreement

In October 2012, the AEP East Companies submitted several filings with the FERC seeking approval to fully separate OPCo's generation assets from its distribution and transmission operations. The filings requested approval to transfer at net book value approximately 9,200 MW of OPCo-owned generation assets to a new wholly-owned company, AEPGenCo. The AEP East Companies also requested FERC approval to transfer at net book value OPCo's current two-thirds ownership (867 MW) in Amos Plant, Unit 3 to APCo and transfer at net book value OPCo's Mitchell Plant to APCo and KPCo in equal one-half interests (780 MW each). Additionally, 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.

3. EFFECTS OF REGULATION

Regulatory assets and liabilities are comprised of the following items:

	December 31, 2012	December 31, 2011	Remaining Recovery Period
Regulatory Assets:	(in thousands)		
Regulatory assets not yet being recovered pending future proceedings to determine the recovery method and timing:			
Regulatory Assets Currently Earning a Return			
Economic Development Rider	$ 13,213	$ 12,572	
Regulatory Assets Currently Not Earning a Return			
Storm Related Costs	61,828	8,375	
Ormet Delayed Payment Arrangement	5,453	-	
Other Regulatory Assets Not Yet Being Recovered	30	-	
Total Regulatory Assets Not Yet Being Recovered	80,524	20,947	
Regulatory assets being recovered:			
Regulatory Assets Currently Earning a Return			
Fuel Adjustment Clause	518,595	506,607	6 years
Deferred Asset Recovery Rider	152,039	173,274	6 years
Capacity Deferral	65,818	-	6 years
Transmission Cost Recovery Rider	49,390	28,404	3 years
RTO Formation/Integration Costs	6,594	7,836	7 years
Economic Development Rider	5,488	11,738	1 year
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	309,684	389,712	12 years
Income Tax Assets	192,332	193,004	21 years
Distribution Decoupling	16,198	-	2 years
Postemployment Benefits	7,658	8,669	5 years
Partnership with Ohio Contribution	2,405	3,400	3 years
Distribution Investment Rider	1,304	-	1 year
Unrealized Loss on Forward Commitments	810	9,930	1 year
Enhanced Service Reliability Plan	557	4,454	1 year
Total Regulatory Assets Being Recovered	1,328,872	1,337,028	
Total FERC Account 182.3 Regulatory Assets	$ 1,409,396	$ 1,357,975	

	December 31, 2012	December 31, 2011	Remaining Refund Period
Regulatory Liabilities:	(in thousands)		
Regulatory liabilities not yet being paid:			
Regulatory Liabilities Currently Paying a Return			
IGCC Preconstruction Costs	$ 4,411	$ 4,196	
Regulatory Liabilities Currently Not Paying a Return			
Other Regulatory Liabilities Not Yet Being Paid	216	216	
Total Regulatory Liabilities Not Yet Being Paid	4,627	4,412	
Regulatory liabilities being paid:			
Regulatory Liabilities Currently Paying a Return			
Economic Development Rider	-	2,428	
Transmission Cost Recovery Rider	-	542	
Regulatory Liabilities Currently Not Paying a Return			
Over-recovered Fuel Costs	14,848	-	1 year
Peak Demand Reduction/Energy Efficiency	12,596	19,124	2 years
Income Tax Liabilities	1,647	2,022	21 years
Over-recovery of Costs Related to gridSMART®	3,501	7,504	2 years
Low Income Customers/Economic Recovery	2,243	2,521	3 years
Total Regulatory Liabilities Being Paid	34,835	34,141	
Total FERC Account 254 Regulatory Liabilities	$ 39,462	$ 38,553	

4. COMMITMENTS, GUARANTEES AND CONTINGENCIES

OPCo is subject to certain claims and legal actions arising in its ordinary course of business. In addition, OPCo'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

OPCo has substantial construction commitments to support its operations and environmental investments. In managing the overall construction program and in the normal course of business, OPCo contractually commits to third-party construction vendors for certain material purchases and other construction services. Management forecasts approximately $617 million of construction expenditures, excluding equity AFUDC and capitalized interest, for 2013.

OPCo 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)	$ 1,167,631	$ 2,012,580	$ 1,542,218	$ 1,368,019	$ 6,090,448
Energy and Capacity Purchase Contracts (b)	45,009	91,997	94,290	920,573	1,151,869
Construction Contracts for Capital Assets (c)	22,407	-	-	-	22,407
Total	$ 1,235,047	$ 2,104,577	$ 1,636,508	$ 2,288,592	$ 7,264,724

(a) Represents contractual commitments to purchase coal, natural gas 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

OPCo 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, extended the $1.75 billion credit facility due in July 2016 to July 2017 and issued a $1 billion interim credit facility due in May 2015 to fund certain OPCo maturities. As of December 31, 2012, OPCo’s maximum future payment for letters of credit issued under the credit facilities was $2.1 million with a maturity of June 2013.

OPCo has $50 million of variable rate Pollution Control Bonds supported by bilateral letters of credit for $50.6 million. In February 2013, OPCo extended its bilateral letter of credit due in March 2013 to July 2014.

Indemnifications and Other Guarantees

Contracts

OPCo 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.

APCo, I&M and OPCo 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

OPCo leases certain equipment under master lease agreements. See “Master Lease Agreements” section of Note 11 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 and sludge. 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. OPCo 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, OPCo is named a Potentially Responsible Party (PRP) for three sites by the Federal EPA. There are three additional sites for which OPCo have received information requests which could lead to PRP designation. In those instances where OPCo 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.

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.

OPERATIONAL CONTINGENCIES

Insurance and Potential Losses

OPCo maintains insurance coverage normal and customary for electric utilities, subject to various deductibles. Insurance coverage includes all risks of physical loss or damage to 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 OPCo. Coverage is generally provided by a combination of the protected cell of EIS and/or various industry mutual and/or commercial insurance carriers.

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. 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. IMPAIRMENTS

2012

Beckjord Plant Unit 6, Conesville Plant Unit 3, Kammer Plant Units 1-3, Muskingum River Plant Units 1-4, Sporn Plant Units 2 and 4 and Picway Plant Unit 5

In October 2012, management filed applications with the FERC proposing to terminate the Interconnection Agreement and seeking to complete the corporate separation of OPCo's generation assets. Based on the intention to terminate the Interconnection Agreement and the FERC filing, management performed an evaluation of the recoverability of generation assets. As a result, in November 2012, management, using generating unit specific estimated future cash flows, concluded that OPCo had a material impairment of certain generation assets. Under a market-based value approach, using level 3 unobservable inputs, management determined that the fair value of these generating units was zero based on the lack of installed environmental control equipment and the nature and condition of these generating units. In the fourth quarter of 2012, OPCo recorded a pretax impairment of $287 million in Other Deductions related to Beckjord Plant Unit 6, Conesville Plant Unit 3, Kammer Plant Units 1-3, Muskingum River Plant Units 1-4, Sporn Plant Units 2 and 4 and Picway Plant Unit 5 generating units which includes $13 million of related material and supplies inventory.

2011

Muskingum River Plant Unit 5 FGD Project (MR5)

In September 2011, subsequent to the stipulation agreement filed with the PUCO, management determined that OPCo was not likely to complete the previously suspended MR5 project and that the project’s preliminary engineering costs were no longer probable of being recovered. As a result, in the third quarter of 2011, OPCo recorded a pretax write-off of $42 million in Operation Expenses.

Sporn Plant Unit 5

In the third quarter of 2011, management decided to no longer offer the output of Sporn Unit 5 into the PJM market. Sporn Unit 5 is not expected to operate in the future, resulting in the removal of Sporn Unit 5 from the Interconnection Agreement. As a result, in the third quarter of 2011, OPCo recorded a pretax write-off of $48 million in Operation Expenses.

6. 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.

OPCO 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. OPCO also participates in OPEB plans sponsored by AEP to provide health and life insurance benefits for retired employees.

OPCO 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. OPCO 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. OPCO 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)	5.00 % (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:

	Pension Plans		Other Postretirement Benefit Plans	
Assumptions	**2012**	**2011**	**2012**	**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 %	5.00 %	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	$ 5,129	$ (4,042)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	30,995	(23,603)

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 tables provide 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	$ 1,016,501	$ 979,781	$ 504,051	$ 491,176
Service Cost	10,979	10,207	8,437	7,537
Interest Cost	44,999	48,144	23,493	24,810
Actuarial Loss	63,464	42,841	40,853	49,596
Plan Amendment Prior Service Credit	-	-	(100,974)	(42,196)
Benefit Payments	(72,472)	(64,472)	(37,669)	(38,055)
Participant Contributions	-	-	8,508	8,786
Medicare Subsidy	-	-	2,501	2,397
Benefit Obligation as of December 31	$ 1,063,471	$ 1,016,501	$ 449,200	$ 504,051
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1	$ 922,283	$ 796,001	$ 310,571	$ 331,904
Actual Gain (Loss) on Plan Assets	118,014	63,208	64,820	(6,634)
Company Contributions	42,549	127,546	18,540	14,570
Participant Contributions	-	-	8,508	8,786
Benefit Payments	(72,472)	(64,472)	(37,669)	(38,055)
Fair Value of Plan Assets as of December 31	$ 1,010,374	$ 922,283	$ 364,770	$ 310,571
Underfunded Status as of December 31	$ (53,097)	$ (94,218)	$ (84,430)	$ (193,480)

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	$ (64)	$ (62)	$ (582)	$ (508)
Accumulated Provision for Pensions and Benefits - Long-term Benefit Liability	(53,033)	(94,156)	(83,848)	(192,972)
Underfunded Status	$ (53,097)	$ (94,218)	$ (84,430)	$ (193,480)

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	$ 498,833	$ 515,569	$ 208,777	$ 224,122
Prior Service Cost (Credit)	1,278	2,019	(141,685)	(44,569)
Transition Obligation	-	-	-	74
Recorded as				
Regulatory Assets	$ 289,931	$ 305,240	$ 19,754	$ 84,472
Deferred Income Taxes	73,563	74,322	16,568	33,304
Net of Tax AOCI	136,617	138,026	30,770	61,851

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	$ 13,572	$ 44,830	$ (2,119)	$ 80,022
Prior Service Credit	-	-	(100,974)	(42,196)
Amortization of Actuarial Loss	(30,308)	(24,721)	(13,226)	(6,933)
Amortization of Prior Service Credit (Cost)	(741)	(1,471)	3,858	212
Amortization of Transition Obligation	-	-	(74)	(106)
Change for the Year	$ (17,477)	$ 18,638	$ (112,535)	$ 30,999

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	$ 281,456	$ -	$ -	$ -	$ 281,456	27.9 %
International	106,889	-	-	-	106,889	10.5 %
Real Estate Investment Trusts	19,484	-	-	-	19,484	1.9 %
Common Collective Trust - International	-	934	-	-	934	0.1 %
Subtotal - Equities	407,829	934	-	-	408,763	40.4 %
Fixed Income:						
Common Collective Trust - Debt	-	6,826	-	-	6,826	0.7 %
United States Government and Agency Securities	-	153,908	-	-	153,908	15.2 %
Corporate Debt	-	265,747	-	-	265,747	26.3 %
Foreign Debt	-	42,737	-	-	42,737	4.2 %
State and Local Government	-	9,462	-	-	9,462	0.9 %
Other - Asset Backed	-	7,663	-	-	7,663	0.8 %
Subtotal - Fixed Income	-	486,343	-	-	486,343	48.1 %
Real Estate	-	-	47,243	-	47,243	4.7 %
Alternative Investments	-	-	42,082	-	42,082	4.2 %
Securities Lending	-	17,284	-	-	17,284	1.7 %
Securities Lending Collateral (a)	-	-	-	(19,547)	(19,547)	(1.9)%
Cash and Cash Equivalents	-	27,058	-	-	27,058	2.7 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	1,148	1,148	0.1 %
Total	$ 407,829	$ 531,619	$ 89,325	$ (18,399)	$ 1,010,374	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	$ 1,366	$ 35,010	$ 34,369	$ 70,745
Actual Return on Plan Assets				
Relating to Assets Still Held as of the Reporting Date	-	6,471	2,203	8,674
Relating to Assets Sold During the Period	(481)	-	1,068	587
Purchases and Sales	(885)	5,762	4,442	9,319
Transfers into Level 3	-	-	-	-
Transfers out of Level 3	-	-	-	-
Balance as of December 31, 2012	$ -	$ 47,243	$ 42,082	$ 89,325

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	$ 98,171	$ -	$ -	$ -	$ 98,171	26.9 %
International	117,374	-	-	-	117,374	32.2 %
Subtotal - Equities	215,545	-	-	-	215,545	59.1 %
Fixed Income:						
Common Collective Trust - Debt	-	16,876	-	-	16,876	4.6 %
United States Government and Agency Securities	-	19,122	-	-	19,122	5.2 %
Corporate Debt	-	36,015	-	-	36,015	9.9 %
Foreign Debt	-	6,088	-	-	6,088	1.7 %
State and Local Government	-	1,693	-	-	1,693	0.5 %
Other - Asset Backed	-	2,286	-	-	2,286	0.6 %
Subtotal - Fixed Income	-	82,080	-	-	82,080	22.5 %
Trust Owned Life Insurance:						
International Equities	-	11,988	-	-	11,988	3.3 %
United States Bonds	-	37,821	-	-	37,821	10.3 %
Cash and Cash Equivalents	14,438	2,653	-	-	17,091	4.7 %
Other - Pending Transactions and Accrued Income (a)	-	-	-	245	245	0.1 %
Total	$ 229,983	$ 134,542	$ -	$ 245	$ 364,770	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	$ 311,798	$ -	$ -	$ -	$ 311,798	33.8 %
International	85,486	-	-	-	85,486	9.3 %
Real Estate Investment Trusts	22,290	-	-	-	22,290	2.4 %
Common Collective Trust - International	-	27,532	-	-	27,532	3.0 %
Subtotal - Equities	419,574	27,532	-	-	447,106	48.5 %
Fixed Income:						
Common Collective Trust - Debt	-	5,628	-	-	5,628	0.6 %
United States Government and Agency Securities	-	121,260	-	-	121,260	13.2 %
Corporate Debt	-	211,046	1,366	-	212,412	23.0 %
Foreign Debt	-	40,865	-	-	40,865	4.4 %
State and Local Government	-	10,300	-	-	10,300	1.1 %
Other - Asset Backed	-	5,573	-	-	5,573	0.6 %
Subtotal - Fixed Income	-	394,672	1,366	-	396,038	42.9 %
Real Estate	-	-	35,010	-	35,010	3.8 %
Alternative Investments	-	-	34,369	-	34,369	3.7 %
Securities Lending	-	46,034	-	-	46,034	5.0 %
Securities Lending Collateral (a)	-	-	-	(50,538)	(50,538)	(5.5)%
Cash and Cash Equivalents	-	19,886	-	-	19,886	2.2 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	(5,622)	(5,622)	(0.6)%
Total	$ 419,574	$ 488,124	$ 70,745	$ (56,160)	$ 922,283	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	$ -	$ 17,168	$ 26,822	$ 43,990
Actual Return on Plan Assets				
Relating to Assets Still Held as of the Reporting Date	-	4,966	2,160	7,126
Relating to Assets Sold During the Period	-	-	742	742
Purchases and Sales	-	12,876	4,645	17,521
Transfers into Level 3	1,366	-	-	1,366
Transfers out of Level 3	-	-	-	-
Balance as of December 31, 2011	$ 1,366	$ 35,010	$ 34,369	$ 70,745

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	$ 76,610	$ -	$ -	$ -	$ 76,610	24.7 %
International	83,792	-	-	-	83,792	27.0 %
Common Collective Trust - Global	-	21,845	-	-	21,845	7.0 %
Subtotal - Equities	160,402	21,845	-	-	182,247	58.7 %
Fixed Income:						
Common Collective Trust - Debt	-	15,248	-	-	15,248	4.9 %
United States Government and Agency Securities	-	17,797	-	-	17,797	5.7 %
Corporate Debt	-	33,516	-	-	33,516	10.8 %
Foreign Debt	-	7,105	-	-	7,105	2.3 %
State and Local Government	-	1,853	-	-	1,853	0.6 %
Other - Asset Backed	-	422	-	-	422	0.1 %
Subtotal - Fixed Income	-	75,941	-	-	75,941	24.4 %
Trust Owned Life Insurance:						
International Equities	-	10,183	-	-	10,183	3.3 %
United States Bonds	-	34,769	-	-	34,769	11.2 %
Cash and Cash Equivalents	3,703	5,159	-	-	8,862	2.9 %
Other - Pending Transactions and Accrued Income (a)	-	-	-	(1,431)	(1,431)	(0.5)%
Total	$ 164,105	$ 147,897	$ -	$ (1,431)	$ 310,571	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	$ 1,044,129	$ 1,001,290
Nonqualified Pension Plans	796	821
Total	$ 1,044,925	$ 1,002,111

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	$ 1,063,471	$ 1,016,501
Accumulated Benefit Obligation	$ 1,044,925	$ 1,002,111
Fair Value of Plan Assets	1,010,374	922,283
Underfunded Accumulated Benefit Obligation	$ (34,551)	$ (79,828)

Estimated Future Benefit Payments and Contributions

OPCO expects contributions and payments for the pension plans of $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, OPCo 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 OPCO'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	$ 72,170	$ 34,025
2014	73,466	34,942
2015	73,636	36,173
2016	75,047	37,811
2017	75,280	38,916
Years 2018 to 2022, in Total	369,388	220,020

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	$ 10,979	$ 10,207	$ 8,437	$ 7,537
Interest Cost	44,999	48,144	23,493	24,810
Expected Return on Plan Assets	(68,121)	(65,198)	(22,459)	(24,415)
Amortization of Transition Obligation	-	-	74	106
Amortization of Prior Service Cost (Credit)	741	1,471	(3,858)	(212)
Amortization of Net Actuarial Loss	30,308	24,721	13,226	6,933
Net Periodic Benefit Cost	18,906	19,345	18,913	14,759
Capitalized Portion	(7,033)	(6,945)	(7,036)	(5,298)
Net Periodic Benefit Cost Recognized as Expense	$ 11,873	$ 12,400	$ 11,877	$ 9,461

Estimated amounts expected to be amortized to net periodic benefit costs 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	$ 35,977	$ 15,621
Prior Service Cost (Credit)	282	(12,871)
Total Estimated 2013 Amortization	$ 36,259	$ 2,750
Expected to be Recorded as		
Regulatory Asset	$ 19,387	$ 599
Deferred Income Taxes	5,905	753
Net of Tax AOCI	10,967	1,398
Total	$ 36,259	$ 2,750

American Electric Power System Retirement Savings Plan

OPCO 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 plan for the years ended December 31, 2012 and 2011 was $10.8 million and $10.1 million, respectively.

7. BUSINESS SEGMENTS

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

8. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

OPCo 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 OPCo due to changes in the underlying market prices or rates. AEPSC, on behalf of OPCo, 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 OPCo. To accomplish these objectives, AEPSC, on behalf of OPCo, 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 OPCo, 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 OPCo, 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 OPCo, 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 OPCo's outstanding derivative contracts as of December 31, 2012 and 2011:

Notional Volume of Derivative Instruments

Primary Risk Exposure	Volume December 31, 2012	Volume December 31, 2011	Unit of Measure
	(in thousands)		
Commodity:			
Power	132,188	229,468	MWhs
Coal	3,033	8,337	Tons
Natural Gas	14,163	10,728	MMBtus
Heating Oil and Gasoline	1,260	1,254	Gallons
Interest Rate	$ 33,934	$ 42,093	USD

Fair Value Hedging Strategies

AEPSC, on behalf of OPCo, 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 OPCo, 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. OPCo does not hedge all commodity price risk.

OPCo’s vehicle fleet is exposed to gasoline and diesel fuel price volatility. AEPSC, on behalf of OPCo, 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.” OPCo does not hedge all fuel price risk.

AEPSC, on behalf of OPCo, 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 OPCo, 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. OPCo does not hedge all interest rate exposure.

At times, OPCo 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 OPCo, 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. OPCo 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," OPCo 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, OPCo 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, OPCo 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**
$ 1,774	$ 15,500	$ 5,810	$ 39,183

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	$ 268,087	$ -	$ -	$ 268,087	$ (175,902)	$ 92,185
Long-Term Portion of Derivative Instrument Assets	85,023	-	-	85,023	(37,022)	48,001
Derivative Instrument Assets – Hedges	-	767	-	767	(351)	416
Long-Term Portion of Derivative Instrument Assets – Hedges	-	303	-	303	(16)	287
Derivative Instrument Liabilities	237,845	-	-	237,845	(189,628)	48,217
Long-Term Portion of Derivative Instrument Liabilities	66,448	-	-	66,448	(41,063)	25,385
Derivative Instrument Liabilities – Hedges	-	2,254	-	2,254	(351)	1,903
Long-Term Portion of Derivative Instrument Liabilities – Hedges	-	596	-	596	(16)	580

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	$ 462,423	$ -	$ -	$ 462,423	$ (355,100)	$ 107,323
Long-Term Portion of Derivative Instrument Assets	136,519	-	-	136,519	(82,940)	53,579
Derivative Instrument Assets – Hedges	-	1,531	-	1,531	(947)	584
Long-Term Portion of Derivative Instrument Assets – Hedges	-	122	-	122	(87)	35
Derivative Instrument Liabilities	441,761	-	-	441,761	(390,549)	51,212
Long-Term Portion of Derivative Instrument Liabilities	112,454	-	-	112,454	(94,951)	17,503
Derivative Instrument Liabilities – Hedges	-	4,186	-	4,186	(947)	3,239
Long-Term Portion of Derivative Instrument Liabilities – Hedges	-	474	-	474	(87)	387

(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	$ 11,978	$ 27,488
Operation Expenses	-	(2)
Regulatory Assets (a)	(14,104)	(17,928)
Regulatory Liabilities (a)	-	(105)
Total Gain (Loss) on Risk Management Contracts	$ (2,126)	$ 9,453

(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.

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.

OPCo 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, OPCo 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), OPCo 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. OPCo recognizes any hedge ineffectiveness in Net Income immediately during the period of change, except in regulated jurisdictions where 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, OPCo designated power, coal and natural gas derivatives as cash flow hedges.

OPCo 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, OPCo designated heating oil and gasoline derivatives as cash flow hedges.

OPCo 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.

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	$ (1,748)	$ 9,454	$ 7,706
Changes in Fair Value Recognized in AOCI	(2,002)	-	(2,002)
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:			
Operating Revenues	(109)	-	(109)
Operation Expenses	2,967	-	2,967
Maintenance Expenses	(5)	-	(5)
Depreciation Expense	-	4	4
Interest on Long-Term Debt	-	(1,363)	(1,363)
Utility Plant	(15)	-	(15)
Regulatory Assets (a)	-	-	-
Regulatory Liabilities (a)	-	-	-
Balance in AOCI as of December 31, 2012	$ (912)	$ 8,095	$ 7,183

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	$ (364)	$ 10,813	$ 10,449
Changes in Fair Value Recognized in AOCI	(2,748)	-	(2,748)
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:			
Operating Revenues	1,457	-	1,457
Operation Expenses	265	-	265
Maintenance Expenses	(141)	-	(141)
Depreciation Expense	-	4	4
Interest on Long-Term Debt	-	(1,363)	(1,363)
Utility Plant	(217)	-	(217)
Regulatory Assets (a)	-	-	-
Regulatory Liabilities (a)	-	-	-
Balance in AOCI as of December 31, 2011	$ (1,748)	$ 9,454	$ 7,706

(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)	$ 416	$ -	$ 416
Hedging Liabilities (a)	1,903	-	1,903
AOCI Gain (Loss) Net of Tax	(912)	8,095	7,183
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(720)	1,359	639

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

	Commodity	Interest Rate and Foreign Currency	Total
		(in thousands)	
Hedging Assets (a)	$ 584	$ -	$ 584
Hedging Liabilities (a)	3,239	-	3,239
AOCI Gain (Loss) Net of Tax	(1,748)	9,454	7,706
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(1,518)	1,359	(159)

(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 OPCo 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 OPCo, 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 OPCo, 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 OPCo, 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, OPCo 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. OPCo has not experienced a downgrade below investment grade. The following table represents: (a) OPCo's fair values of such derivative contracts, (b) the amount of collateral OPCo 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 OPCo Would Have Been Required to Post	Amount Attributable to RTO and ISO Activities
		(in thousands)	
December 31, 2012	$ 3,034	$ 5,198	$ 4,933
December 31, 2011	13,550	8,410	8,410

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

In addition, a majority of OPCo'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 OPCo and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering OPCo'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	$ 69,516	$ 2,561	$ 42,386
December 31, 2011	104,091	10,978	37,380

9. 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)			
$ 3,860,440	$ 4,560,337	$ 4,054,148	$ 4,665,739

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)		
Special Deposits (a)	$ -	$ 26	$ -	$ 39	$ 65
Derivative Instrument Assets					
Risk Management Commodity Contracts (b) (c)	5,848	238,254	23,973	(175,890)	92,185
Derivative Instrument Assets – Hedges					
Cash Flow Hedges – Commodity (b)	-	688	-	(272)	416
Total Assets	$ 5,848	$ 238,968	$ 23,973	$ (176,123)	$ 92,666
Liabilities:					
Derivative Instrument Liabilities					
Risk Management Commodity Contracts (b) (c)	$ 2,753	$ 226,536	$ 8,544	$ (189,616)	$ 48,217
Derivative Instrument Liabilities – Hedges					
Cash Flow Hedges – Commodity (b)	-	2,175	-	(272)	1,903
Total Liabilities	$ 2,753	$ 228,711	$ 8,544	$ (189,888)	$ 50,120

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)		
Special Deposits (a)	$ 26	$ -	$ -	$ 22	$ 48
Derivative Instrument Assets					
Risk Management Commodity Contracts (b) (c)	6,339	421,249	34,425	(356,766)	105,247
De-designated Risk Management Contracts (d)	-	-	-	2,076	2,076
Total Derivative Instrument Assets	6,339	421,249	34,425	(354,690)	107,323
Derivative Instrument Assets – Hedges					
Cash Flow Hedges – Commodity (b)	-	1,483	-	(899)	584
Total Assets	$ 6,365	$ 422,732	$ 34,425	$ (355,567)	$ 107,955
Liabilities:					
Derivative Instrument Liabilities					
Risk Management Commodity Contracts (b) (c)	$ 3,433	$ 406,259	$ 31,659	$ (390,139)	$ 51,212
Derivative Instrument Liabilities – Hedges					
Cash Flow Hedges – Commodity (b)	-	4,038	100	(899)	3,239
Total Liabilities	$ 3,433	$ 410,297	$ 31,759	$ (391,038)	$ 54,451

(a) Amounts in “Other” column primarily represent cash deposits with third parties. Level 1 and Level 2 amounts primarily represent investments in money market funds.
(b) Amounts in “Other” column primarily represent counterparty netting of risk management and hedging contracts and associated cash collateral under the accounting guidance for “Derivatives and Hedging.”
(c) Substantially comprised of power contracts.
(d) 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.

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	$ 2,666
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(7,452)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	5,401
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	28
Purchases, Issuances and Settlements (c)	16,214
Transfers into Level 3 (d) (e)	1,909
Transfers out of Level 3 (e) (f)	(2,527)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	(810)
Balance as of December 31, 2012	$ 15,429

Year Ended December 31, 2011	**Net Risk Management Assets (Liabilities)**
	(in thousands)
Balance as of December 31, 2010	$ 6,583
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(2,711)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	7,741
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	(100)
Purchases, Issuances and Settlements (c)	1,858
Transfers into Level 3 (d) (e)	3,257
Transfers out of Level 3 (e) (f)	(4,032)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	(9,930)
Balance as of December 31, 2011	$ 2,666

(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 Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input (a)	Forward Price Range Low	Forward Price Range High
	(in thousands)					
Energy Contracts	$ 21,516	$ 5,510	Discounted Cash Flow	Forward Market Price	$ 9.40	$ 68.80
FTRs	2,457	3,034	Discounted Cash Flow	Forward Market Price	(3.21)	14.79
Total	$ 23,973	$ 8,544				

(a) Represents market prices in dollars per MWh.

10. INCOME TAXES

The details of OPCo's income taxes as reported are as follows:

	Years Ended December 31, 2012	2011
	(in thousands)	
Charged (Credited) to Operating Expenses, Net:		
Current	$ 100,511	$ 173,525
Deferred	145,037	53,854
Deferred Investment Tax Credits	(1,768)	(2,093)
Total	243,780	225,286
Charged (Credited) to Nonoperating Income, Net:		
Current	1,111	(78,373)
Deferred	(100,292)	67,269
Deferred Investment Tax Credits	(81)	(287)
Total	(99,262)	(11,391)
Income Tax Expense	$ 144,518	$ 213,895

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	$ 343,534	$ 464,992
Income Tax Expense	144,518	213,895
Pretax Income	$ 488,052	$ 678,887
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 170,818	$ 237,610
Increase (Decrease) in Income Taxes resulting from the following items:		
Depreciation	5,239	6,368
Investment Tax Credits, Net	(1,849)	(2,380)
State and Local Income Taxes, Net	(18,291)	(3,222)
Parent Company Loss Benefit	(11,915)	(6,989)
Other	516	(17,492)
Income Tax Expense	$ 144,518	$ 213,895
Effective Income Tax Rate	29.6%	31.5%

The following table shows elements of OPCo's net deferred tax liability and significant temporary differences:

	December 31, 2012	2011
	(in thousands)	
Deferred Tax Assets	$ 497,599	$ 565,662
Deferred Tax Liabilities	(2,841,935)	(2,824,714)
Net Deferred Tax Liabilities	$ (2,344,336)	$ (2,259,052)
Property Related Temporary Differences	$ (2,054,027)	$ (1,958,167)
Amounts Due from Customers for Future Federal Income Taxes	(59,291)	(59,699)
Deferred State Income Taxes	(90,358)	(98,774)
Deferred Income Taxes on Other Comprehensive Loss	86,263	103,476
Impairment Loss	100,459	-
Accrued Pensions	(43,397)	(30,543)
Regulatory Assets	(190,273)	(205,925)
Deferred Fuel and Purchased Power	(199,997)	(194,509)
Postretirement Benefits	47,204	71,546
All Other, Net	59,081	113,543
Net Deferred Tax Liabilities	$ (2,344,336)	$ (2,259,052)

AEP System Tax Allocation Agreement

OPCo 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

OPCo and other AEP subsidiaries are no longer subject to U.S. federal examination for years before 2009. OPCo 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 OPCo's 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, OPCo 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.

OPCo and other AEP subsidiaries file income tax returns in various state and local jurisdictions. These taxing authorities routinely examine the tax returns. OPCo 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, OPCo and other AEP subsidiaries are no longer subject to state or local income tax examinations by tax authorities for years before 2008. In March 2012, AEP settled all outstanding franchise tax issues with the state of Ohio for the years 2000 through 2009. The settlements did not materially impact OPCo's net income, cash flows or financial condition.

Net Income Tax Operating Loss Carryforward

As of December 31, 2012, OPCo had a state net income tax operating loss carryforward of $313 million for West Virginia that expires in 2032. As a result, OPCo accrued deferred state and local income tax benefits in 2011 and 2012 and expects to realize the state and local cash flow benefits 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 net income tax operating losses in 2011 and 2009 along with lower federal taxable income, resulting in unused federal income tax credits. As of December 31, 2012, OPCo has federal tax credit carryforwards of $21.3 million. If these credits are not utilized, federal general business tax credits will expire in the years 2028 through 2031.

OPCo anticipates future federal taxable income will be sufficient to realize the tax benefits of the federal tax credits before they expire unused.

Uncertain Tax Positions

OPCo recognizes 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	$ 266	$ 1,213
Interest Income	-	5,173
Reversal of Prior Period Interest Expense	504	4,019

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	$ -	$ 869
Accrual for Payment of Interest and Penalties	451	1,513

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

	2012	2011
	(in thousands)	
Balance as of January 1,	$ 43,565	$ 68,655
Increase - Tax Positions Taken During a Prior Period	1,360	11,330
Decrease - Tax Positions Taken During a Prior Period	(13,582)	(20,299)
Increase - Tax Positions Taken During the Current Year	-	-
Decrease - Tax Positions Taken During the Current Year	-	-
Decrease - Settlements with Taxing Authorities	(20,291)	(6,935)
Decrease - Lapse of the Applicable Statute of Limitations	-	(9,186)
Balance as of December 31,	$ 11,052	$ 43,565

Management believes that there will be no significant net increase or decrease in unrecognized benefits within 12 months of the reporting date. The total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate was $674 thousand and $21.1 million for 2012 and 2011, respectively.

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 OPCo’s net income or financial condition but are expected to have a favorable impact on cash flows in 2013.

State Tax Legislation

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. In addition, Michigan repealed its Business Tax regime in May 2011 and replaced it with a traditional corporate net income tax with a rate of 6%, effective January 1, 2012. The enacted provisions will not materially impact OPCo’s net income, cash flows or financial condition.

11. <u>LEASES</u>

Leases of property, plant and equipment are for periods up to 60 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	**2011**
	(in thousands)	
Net Lease Expense on Operating Leases	$ 59,836	$ 59,971
Amortization of Capital Leases	10,905	12,891
Interest on Capital Leases	3,303	3,747
Total Lease Rental Costs	$ 74,044	$ 76,609

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

	December 31, 2012	December 31, 2011
	(in thousands)	
Property, Plant and Equipment Under Capital Leases		
Production	$ 39,080	$ 36,689
Other Property, Plant and Equipment	35,666	36,264
Total Property, Plant and Equipment	74,746	72,953
Accumulated Amortization	27,513	22,075
Net Property, Plant and Equipment Under Capital Leases	$ 47,233	$ 50,878
Obligations Under Capital Leases:		
Noncurrent	$ 36,381	$ 40,152
Current	14,707	14,096
Total Obligations Under Capital Leases	$ 51,088	$ 54,248

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

	Capital Leases	Noncancelable Operating Leases
	(in thousands)	
2013	$ 13,669	$ 58,968
2014	10,371	55,261
2015	7,383	52,287
2016	6,743	46,002
2017	6,322	42,678
Later Years	17,905	68,094
Total Future Minimum Lease Payments	62,393	$ 323,290
Less Estimated Interest Element	11,305	
Estimated Present Value of Future Minimum Lease Payments	$ 51,088	

Master Lease Agreements

OPCo 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, OPCo 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 $4 million. Historically, at the end of the lease term the fair value has been in excess of the unamortized balance.

12. FINANCING ACTIVITIES

Preferred Stock

In December 2011, OPCo redeemed all of its outstanding preferred stock, resulting in a loss. The par value of preferred stock redeemed and the loss recorded was $16.6 million and $488 thousand, respectively. The numbers of shares redeemed for the year ended December 31, 2011 are as follows:

Series	Number of Shares Redeemed
4.08 %	14,495
4.20 %	22,824
4.40 %	31,482
4.50 %	97,357

Long-term Debt

There are certain limitations on establishing liens against OPCo's assets under indentures. None of the long-term debt obligations of OPCo 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	2012-2035	5.84%	4.85%-6.60%	0.955%-6.60%	$ 3,150,000	$ 3,300,000
Pollution Control Bonds (a)	2012-2038 (b)	3.72%	0.13%-5.80%	0.07%-5.80%	517,825	562,325
Notes Payable - Affiliated	2015	5.25%	5.25%	5.25%	200,000	200,000
Unamortized Discount, Net					(7,385)	(8,177)
Total Long-term Debt					$ 3,860,440	$ 4,054,148

(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.

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

	(in thousands)
2013	$ 856,000
2014	403,580
2015	286,000
2016	350,000
2017	-
After 2017	1,972,245
Principal Amount	3,867,825
Unamortized Discount, Net	(7,385)
Total Long-term Debt Outstanding	$ 3,860,440

In February 2013, OPCo retired $250 million of 5.5% Senior Unsecured Notes due in 2013.

In March 2013, OPCo issued $200 million of variable rate intercompany debt from AEP due in 2015.

In March 2013, OPCo retired $250 million of 5.5% Senior Unsecured Notes due in 2013.

In March 2013, OPCo retired $50 million of variable rate Pollution Control Bonds due in 2014. The variable rate bonds were held by a trustee on behalf of OPCo.

As of December 31, 2012, trustees held, on behalf of OPCo, $463 million of its reacquired Pollution Control Bonds.

Dividend Restrictions

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

Federal Power Act

The Federal Power Act prohibits OPCo 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 OPCo.

None of these restrictions limit the ability of OPCo to pay dividends out of retained earnings.

Leverage Restrictions

Pursuant to the credit agreement leverage restrictions, OPCo 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 OPCo’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. OPCo'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	$ 126,975	$ 278,923	$ 47,820	$ 119,252	$ 106,293	$ 600,000
2011	46,761	443,223	31,365	223,169	209,223	600,000

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	0.48%	0.46%	0.56%	0.39%	0.47%	0.47%
2011	0.45%	0.44%	0.56%	0.06%	0.45%	0.35%

Interest expense related to the Utility Money Pool is included in Interest on Debt to Associated Companies. OPCo incurred interest expense for amounts borrowed from the Utility Money Pool of $572 thousand and $12 thousand for the years ended December 31, 2012 and 2011, respectively.

Interest income related to the Utility Money Pool is included in Interest and Dividend Income. OPCo earned interest income for amounts advanced to the Utility Money Pool of $1 million and $795 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, OPCo 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 costs, administrative costs and OPCo's uncollectible accounts experience. OPCo 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 $301 million and $347 million, respectively.

The fees paid to AEP Credit for customer accounts receivable sold were $20.3 million and $18.9 million for the years ended December 31, 2012 and 2011, respectively.

OPCo's proceeds on the sale of receivables to AEP Credit were $3 billion and $3.5 billion for the years ended December 31, 2012 and 2011, respectively.

13. RELATED PARTY TRANSACTIONS

For other related party transactions, also see "AEP System Tax Allocation Agreement" section of Note 10 in addition to "Utility Money Pool – AEP System" and "Sale of Receivables – AEP Credit" sections of Note 12.

Interconnection Agreement

OPCo, along with APCo, I&M, KPCo and AEPSC are parties to the Interconnection Agreement, which defines the sharing of costs and benefits associated with the respective 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, OPCo, along with APCo, I&M and KPCo 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 with the FERC seeking approval to fully separate OPCo's generating assets from its distribution and transmission operations. Additionally, 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 "Corporate Separation and 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. Revenues and costs arising from third party sales are generally shared based on the amount of energy PSO or SWEPCo contributes that is sold to third parties.

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 based on a statutory formula as Ohio transitions to the use of market rates for generation.

Under both the Interconnection Agreement and CSW Operating Agreement, power generated that is not needed to serve the AEP System's native load 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	$ 643,486	$ 823,703
Direct Sales to East Affiliates	136,142	115,120
Direct Sales to West Affiliates	454	1,936
Transmission Agreement and Transmission Coordination Agreement Sales	26,295	3,375
Natural Gas Contracts with AEPES	-	196
Other Revenues	40,917	33,669

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	$ 174,240	$ 326,871
Direct Purchases from West Affiliates	75	312
Purchases from AEGCo	203,583	185,741
Gas Purchases from AEPES	2,808	2,689

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 new 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). The new TA was phased-in for retail rates and added KGPCo and WPCo as parties to the agreement. OPCo's net charges recorded related to the new TA for the years ended December 31, 2012 and 2011 were $6.1 million and $17.2 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)

In March 2007, OPCo and AEGCo entered into a ten-year UPA for the entire output from the Lawrenceburg Generating Station effective with AEGCo's purchase of the plant in May 2007. The UPA has an option for an additional two-year period. I&M operates the plant under an agreement with AEGCo. Under the UPA, OPCo pays AEGCo for the capacity, depreciation, fuel, operation and maintenance and tax expenses. These payments are due regardless of whether the plant is operating. The fuel and operation and maintenance payments are based on actual costs incurred. All expenses are trued up periodically.

Cook Coal Terminal

Cook Coal Terminal, a division of OPCo, performs coal transloading services at cost for APCo and I&M. OPCo included revenues of $33.6 million and $21.9 million for the years ended December 31, 2012 and 2011, respectively, for these services in Revenues from Nonutility Operations and expenses in Expenses from Nonutility Operations.

Cook Coal Terminal also performs railcar maintenance services at cost for APCo, I&M, PSO and SWEPCo. OPCo included revenues for these services in Revenues from Nonutility Operations and expenses in Expenses from Nonutility Operations. OPCo's railcar maintenance revenues in 2012 and 2011 were $5.8 million and $5.9 million, respectively.

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. OPCo paid $40 million and $37 million for the years ended December 31, 2012 and 2011, respectively, to I&M and recorded the costs as fuel expense or other operation expense.

Central Machine Shop

APCo operates a facility which repairs and rebuilds specialized components for the generation plants across the AEP System. OPCo recorded these billings of $3.8 million and $3.7 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. OPCo 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	I&M	KPCo	PSO	SWEPCo
				(in thousands)		
Payment of Costs:						
	2012	$ 854	$ 170	$ -	$ 5	$ 99
	2011	840	170	-	8	66
Reimbursement of Costs:						
	2012	1,960	889	41	74	321
	2011	1,373	1,190	355	234	605

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

OPCo paid $125 million and $145 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 amount recorded for OPCo for the year ended December 31, 2011 was $27.6 million.

Sales and Purchases of Property

OPCo 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	**2011**
	(in thousands)	
Sales	$ 4,163	$ 12,113
Purchases	10,608	3,045

Global Borrowing Notes

As of December 31, 2012 and 2011, AEP has an intercompany note in place with OPCo. The debt is reflected in Advances from Associated Companies on the balance sheets. OPCo accrues interest for the global borrowing and remits the interest to AEP.

Intercompany Billings

OPCo 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. OPCo's total billings from AEPSC were $277 million and $280 million for the years ended December 31, 2012 and 2011, respectively.

14. PROPERTY, PLANT AND EQUIPMENT

Depreciation

OPCo 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	Steam	Other	Hydro	Transmission	Distribution	General
			(in percentages)			
2012	3.8	2.3	2.7	2.3	2.7	1.1
2011	3.2	2.3	2.7	2.3	3.7	8.7

For rate-regulated operations, 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. For nonregulated operations, non-ARO removal costs are expensed as incurred.

Asset Retirement Obligations (ARO)

OPCo 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. OPCo 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 OPCo plans to use its facilities indefinitely. The retirement obligation would only be recognized if and when OPCo abandons or ceases the use of specific easements, which is not expected.

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

Year	ARO as of January 1,	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates	ARO as of December 31,
			(in thousands)			
2012	$ 237,120	$ 14,836	$ -	$ (8,223)	$ 21,293	$ 265,026
2011	184,824	13,236	165	(4,870)	43,765	237,120

Jointly-owned Electric Facilities

OPCo has electric facilities that are jointly-owned with affiliated and nonaffiliated companies. Using its own financing, OPCo is obligated to pay its share of the costs of any such jointly-owned facilities in the same proportion as its ownership interest. OPCo'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:

			OPCo's Share as of December 31, 2012		
	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in thousands)	
John E. Amos Generating Station (Unit No. 3) (a)	Coal	66.67 %	$ 995,005	$ 14,093	$ 213,163
W.C. Beckjord Generating Station (Unit No. 6) (b)	Coal	12.5 %	-	-	-
Conesville Generating Station (Unit No. 4) (c)	Coal	43.5 %	310,342	26,067	58,677
J.M. Stuart Generating Station (d)	Coal	26.0 %	541,719	11,151	180,687
Wm. H. Zimmer Generating Station (e)	Coal	25.4 %	807,431	1,817	387,209
Transmission	NA	(f)	69,148	4,101	50,516
Total			$ 2,723,645	$ 57,229	$ 890,252

			OPCo's Share as of December 31, 2011		
	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in thousands)	
John E. Amos Generating Station (Unit No. 3) (a)	Coal	66.67 %	$ 988,510	$ 15,344	$ 188,820
W.C. Beckjord Generating Station (Unit No. 6) (b)	Coal	12.5 %	19,131	108	8,476
Conesville Generating Station (Unit No. 4) (c)	Coal	43.5 %	309,771	11,633	53,980
J.M. Stuart Generating Station (d)	Coal	26.0 %	528,271	13,292	171,830
Wm. H. Zimmer Generating Station (e)	Coal	25.4 %	771,158	19,949	376,585
Transmission	NA	(f)	63,115	5,805	49,487
Total			$ 2,679,956	$ 66,131	$ 849,178

(a) Operated by APCo.
(b) Operated by Duke Energy Corporation, a nonaffiliated company. OPCo's portion of this unit was impaired in the fourth quarter of 2012. See "Impairments" section of Note 5.
(c) Operated by OPCo.
(d) Operated by The Dayton Power & Light Company, a nonaffiliated company.
(e) Operated by Duke Energy Corporation, a nonaffiliated company.
(f) Varying percentages of ownership.
NA Not applicable.

15. COST REDUCTION PROGRAMS

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.

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

Expense Allocation from AEPSC	Incurred for Registrant Subsidiaries	Settled	Remaining Balance as of December 31, 2012
	(in thousands)		
$ 9,225	$ 4,273	$ (10,048)	$ 3,450

2010 Cost Reduction Initiatives

In April 2010, management began initiatives to decrease both labor and non-labor expenses with a goal of achieving significant reductions in operation and maintenance expenses. A total of 2,461 positions was eliminated across the AEP System as a result of process improvements, streamlined organizational designs and other efficiencies. Many of these eliminated positions resulted from employees that elected retirement through voluntary severance. Most of the affected employees terminated employment as of May 31, 2010. The severance program provided two weeks of base pay for every year of service along with other severance benefits.

For OPCo, who had cost reduction activity remaining as of December 31, 2011, the activity for 2012 is described in the following table:

Balance as of December 31, 2011	Settled	Adjustments	Balance as of December 31, 2012
	(in thousands)		
$ 138	$ (138)	$ -	$ -

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			(165,525)	(190,604,389)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income			4,473	10,850,385
3	Preceding Quarter/Year to Date Changes in Fair Value				(25,674,441)
4	Total (lines 2 and 3)			4,473	(14,824,056)
5	Balance of Account 219 at End of Preceding Quarter/Year			(161,052)	(205,428,445)
6	Balance of Account 219 at Beginning of Current Year			(161,052)	(205,428,445)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income			4,474	12,961,092
8	Current Quarter/Year to Date Changes in Fair Value				19,559,093
9	Total (lines 7 and 8)			4,474	32,520,185
10	Balance of Account 219 at End of Current Quarter/Year			(156,578)	(172,908,260)

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	10,978,344	(363,372)	(180,154,942)		
2	(1,363,483)	1,363,925	10,855,300		
3		(2,747,552)	(28,421,993)		
4	(1,363,483)	(1,383,627)	(17,566,693)	464,992,339	447,425,646
5	9,614,861	(1,746,999)	(197,721,635)		
6	9,614,861	(1,746,999)	(197,721,635)		
7	(1,363,481)	2,838,236	14,440,321		
8		(2,002,331)	17,556,762		
9	(1,363,481)	835,905	31,997,083	343,534,107	375,531,190
10	8,251,380	(911,094)	(165,724,552)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio 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)	15,430,834,664	15,430,834,664
4	Property Under Capital Leases	47,233,276	47,233,276
5	Plant Purchased or Sold		
6	Completed Construction not Classified	313,283,310	313,283,310
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	15,791,351,250	15,791,351,250
9	Leased to Others		
10	Held for Future Use	16,588,944	16,588,944
11	Construction Work in Progress	354,496,915	354,496,915
12	Acquisition Adjustments	636,578	636,578
13	Total Utility Plant (8 thru 12)	16,163,073,687	16,163,073,687
14	Accum Prov for Depr, Amort, & Depl	6,670,266,900	6,670,266,900
15	Net Utility Plant (13 less 14)	9,492,806,787	9,492,806,787
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	6,548,879,409	6,548,879,409
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	120,774,423	120,774,423
22	Total In Service (18 thru 21)	6,669,653,832	6,669,653,832
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation	50,531	50,531
29	Amortization		
30	Total Held for Future Use (28 & 29)	50,531	50,531
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj	562,537	562,537
33	Total Accum Prov (equals 14) (22,26,30,31,32)	6,670,266,900	6,670,266,900

Name of Respondent Ohio 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

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

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
					3
					4
					5
					6
					7
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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		
4	Allowance for Funds Used during Construction		
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)		
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		
9	In Reactor (120.3)		
10	SUBTOTAL (Total 8 & 9)		
11	Spent Nuclear Fuel (120.4)		
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)		
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)		
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)		

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.
			1
			2
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Name of Respondent Ohio 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

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

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of 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)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	5,584	
3	(302) Franchises and Consents	71,469	
4	(303) Miscellaneous Intangible Plant	130,693,913	30,814,913
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	130,770,966	30,814,913
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	13,665,713	748,598
9	(311) Structures and Improvements	659,792,941	13,190,330
10	(312) Boiler Plant Equipment	6,871,677,732	109,764,904
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	900,026,295	39,472,852
13	(315) Accessory Electric Equipment	333,584,066	4,347,373
14	(316) Misc. Power Plant Equipment	117,447,139	4,538,221
15	(317) Asset Retirement Costs for Steam Production	138,495,703	21,285,974
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	9,034,689,589	193,348,252
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbogenerator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	3,992	
28	(331) Structures and Improvements	49,979,341	
29	(332) Reservoirs, Dams, and Waterways	6,304,465	
30	(333) Water Wheels, Turbines, and Generators	43,864,725	
31	(334) Accessory Electric Equipment	10,010,232	17,670
32	(335) Misc. Power PLant Equipment	4,430,790	3,613
33	(336) Roads, Railroads, and Bridges		
34	(337) Asset Retirement Costs for Hydraulic Production	50,034	
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	114,643,579	21,283
36	D. Other Production Plant		
37	(340) Land and Land Rights	3,713,584	
38	(341) Structures and Improvements	14,495,497	3,767,832
39	(342) Fuel Holders, Products, and Accessories	7,547,998	45,075
40	(343) Prime Movers		
41	(344) Generators	324,528,308	2,446,449
42	(345) Accessory Electric Equipment	45,996,888	764,124
43	(346) Misc. Power Plant Equipment	8,484,005	451,864
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	404,766,280	7,475,344
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	9,554,099,448	200,844,879

Name of Respondent Ohio 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

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	103,698,082	4,700,485
49	(352) Structures and Improvements	85,440,234	99,361
50	(353) Station Equipment	1,041,206,527	36,151,051
51	(354) Towers and Fixtures	172,913,590	118,819
52	(355) Poles and Fixtures	225,376,475	19,317,161
53	(356) Overhead Conductors and Devices	283,108,996	15,454,789
54	(357) Underground Conduit	10,893,770	
55	(358) Underground Conductors and Devices	19,686,427	
56	(359) Roads and Trails		
57	(359.1) Asset Retirement Costs for Transmission Plant	3,120	
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	1,942,327,221	75,841,666
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	49,758,376	2,350,183
61	(361) Structures and Improvements	20,443,066	23,507
62	(362) Station Equipment	507,013,227	30,247,253
63	(363) Storage Battery Equipment	5,062,199	
64	(364) Poles, Towers, and Fixtures	582,110,980	20,629,161
65	(365) Overhead Conductors and Devices	564,481,857	47,134,773
66	(366) Underground Conduit	158,130,586	19,138,085
67	(367) Underground Conductors and Devices	489,513,049	32,064,755
68	(368) Line Transformers	643,093,543	29,002,431
69	(369) Services	282,626,314	11,855,540
70	(370) Meters	155,764,648	31,905,973
71	(371) Installations on Customer Premises	48,844,295	3,261,782
72	(372) Leased Property on Customer Premises	103,793	
73	(373) Street Lighting and Signal Systems	33,937,372	2,949,779
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	3,540,883,305	230,563,222
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	8,215,449	
87	(390) Structures and Improvements	128,168,414	2,161,047
88	(391) Office Furniture and Equipment	8,078,909	16,621
89	(392) Transportation Equipment	70,645	
90	(393) Stores Equipment	618,560	13,046
91	(394) Tools, Shop and Garage Equipment	29,556,345	2,827,638
92	(395) Laboratory Equipment	1,210,346	
93	(396) Power Operated Equipment	633,681	
94	(397) Communication Equipment	49,628,763	7,661,323
95	(398) Miscellaneous Equipment	3,763,559	311,825
96	SUBTOTAL (Enter Total of lines 86 thru 95)	229,944,671	12,991,500
97	(399) Other Tangible Property	581,471	-56,461
98	(399.1) Asset Retirement Costs for General Plant	298,648	7,393
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	230,824,790	12,942,432
100	TOTAL (Accounts 101 and 106)	15,398,905,730	551,007,112
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	15,398,905,730	551,007,112

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

distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.

9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
			5,584		2
			71,469		3
22,621,907			138,886,919		4
22,621,907			138,963,972		5
					6
					7
			14,414,311		8
5,010,625		-2,774	667,969,872		9
84,865,844		39,830	6,896,616,622		10
					11
18,845,129			920,654,018		12
4,268,083		24,396	333,687,752		13
2,068,122		7,320	119,924,558		14
3,050,389			156,731,288		15
118,108,192		68,772	9,109,998,421		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
			3,992		27
			49,979,341		28
			6,304,465		29
			43,864,725		30
9,700			10,018,202		31
			4,434,403		32
					33
			50,034		34
9,700			114,655,162		35
					36
			3,713,584		37
174,947			18,088,382		38
3,208			7,589,865		39
					40
791,945			326,182,812		41
211,546			46,549,466		42
6,235		1	8,929,635		43
					44
1,187,881		1	411,053,744		45
119,305,773		68,773	9,635,707,327		46

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

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
1,603		-341,392	108,055,572		48
2,649		-140,341	85,396,605		49
6,911,231		79,067	1,070,525,414		50
8,928			173,023,481		51
2,684,523		-2	242,009,111		52
421,834		-1	298,141,950		53
			10,893,770		54
			19,686,427		55
					56
			3,120		57
10,030,768		-402,669	2,007,735,450		58
					59
		-212,510	51,896,049		60
161			20,466,412		61
3,189,578		-6,078	534,064,824		62
			5,062,199		63
5,397,832		-75	597,342,234		64
10,996,779		6,155	600,626,006		65
201,805			177,066,866		66
3,949,467			517,628,337		67
10,562,523			661,533,451		68
2,517,741		-48,490	291,915,623		69
13,632,907			174,037,714		70
1,604,289			50,501,788		71
			103,793		72
1,018,976			35,868,175		73
					74
53,072,058		-260,998	3,718,113,471		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
		352,526	8,567,975		86
482,630		-2,951	129,843,880		87
		-7,321	8,088,209		88
			70,645		89
			631,606		90
			32,383,983		91
40,139		-74,293	1,095,914		92
11,353			622,328		93
		48,490	57,338,576		94
26,090		74,293	4,123,587		95
560,212		390,744	242,766,703		96
			525,010		97
			306,041		98
560,212		390,744	243,597,754		99
205,590,718		-204,150	15,744,117,974		100
					101
					102
					103
205,590,718		-204,150	15,744,117,974		104

Schedule Page: 204 Line No.: 97 Column: g

Nature and Use of Plant Included in Account 399

Land and Land Rights	$429,000
Coal Exploration Equipment	$96,010
	$525,010

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

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1					
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44					
45					
46					
47	TOTAL				

Name of Respondent Ohio 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

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	North Corridor Marysville Substation 765 KV			
3	Right-of-Way (9520)	02/01/96		418,481
4				
5	Marysville 765KV Substation (2337)	02/01/76		263,474
6				
7	Ridgely Substation (3607)	3/1/2010	2013	469,403
8				
9	Newbury Project (5674)	12/80		4,991,594
10		12/87		61,220
11				
12	Ohio Operations Center (0528)	6/81		506,771
13				
14	North Galloway - West Jefferson 69kV Right-of-Way	5/98		254,004
15	(5684)			
16				
17	Bolton Substation (0269)	5/05	2019	732,264
18				
19	Items Under $250,000			3,553,656
20				
21	Other Property:			
22				
23	Items under $250,000			57,307
24				
25				
26				
27				
28				
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44				
45				
46				
47	Total			16,588,944

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio 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	Berrywood Substation (0276)	3/06	2017	252,572
3				
4	Lincoln - Berrywood 69kV (C977)	6/09	2017	256,991
5				
6	Lucasville Service Center (3276)	12/01/2011	2014	447,815
7				
8	South Worthington 138/34.5kV Substation (0383)	8/09	2013	699,997
9				
10	Shanahan Substation (0277)	11/1/2010	2015	264,761
11				
12	South Point Service Center (3069)	7/1/2011	2013	1,074,567
13				
14	Vassell Substation (0300)	5/08	2014	2,284,067
15				
16				
17				
18				
19				
20				
21	Other Property:			
22				
23				
24				
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41				
42				
43				
44				
45				
46				
47	Total			16,588,944

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

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	AM FGD Landfill	2,359,652
2	CV U4-6 FGD Landfill	8,102,179
3	TL/OPC/Cambridge Area Subtrans	1,080,560
4	TSOPCPurchase-Rebuild Maj Eq	1,112,998
5	TSOPCOPortsmouth Subtrans	1,322,379
6	TSOPCOWest Moulton Station	5,048,825
7	T/CSP/Security Application Enh	9,911,688
8	TL/CSP/Hyatt-Corridor 345	5,263,935
9	CV CI U4 GSU REPLACEMENT	2,184,472
10	GV U0 Hg at Outfall	6,077,951
11	ML U1&2 Dry Fly Ash Conversion	33,749,639
12	CV CI U4 SILO DUST SUPPRESSON	1,464,891
13	CV CI U56 SILO DUST SUPPRESSON	5,328,931
14	Amos Landfill Seq. 3, 4 OPCo	1,015,753
15	U3 LP Ugrade Shadow Project	7,587,208
16	CD0 Landfill Cells	6,688,063
17	T/CSP/Maj Storm	1,827,292
18	CV CI U4 Jet Bubbling Reactor	7,996,333
19	CV CI U4 HP TURBINE UPGRADE	7,081,300
20	CV CI U456 FGD LANDFL VERT EXP	1,065,542
21	CV CI U4 COAL PIPE REPL	2,185,102
22	CSP/Gay Street Station	1,495,433
23	OP/Install UG Circuit Exit	1,093,804
24	CSP/Cols Arc Flash Mitigation	1,407,414
25	Battelle Assistance and Other	10,816,680
26	Community Energy Storage	2,294,334
27	Cyber Security	3,127,053
28	Oh gSmart Ph1 DA	4,675,842
29	Oh gSmart Ph1 HAN	2,098,801
30	GV Landfill Extension	5,295,247
31	Upgrade LP A,B,C,D Turb Rotor	7,872,424
32	SCR Catalysts	1,694,488
33	ML E BARGE UNLOADER CONTROLS	1,317,288
34	ML New Landfill	10,735,334
35	ML New Landfill Haul Road	4,167,144
36	ML0-S-AUX BOILER REPLACEMENT	20,017,293
37	ML1 S AIR HEATER BASKET REPLAC	1,842,735
38	Elk Run (Carter Hollow LF)	3,113,692
39	T/OPCO/Line Rebuild	2,318,460
40	T/CSP/Line Rebuild	1,182,939
41	TS/OH/Replace & Refurbish	1,840,216
42	DS/OH/Replace & Refurbish	1,901,279
43	TOTAL	354,496,915

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	T/OPCO/Line Rehab/Replace	1,883,702
2	T/CSP/Line Rehab/Replace	1,180,609
3	T/OP/Purchase/Rebuild Maj Eqp	1,076,044
4	T/CSP/Purchase/Rebuild Maj Eqp	1,493,067
5	D/OH/Purchase/Rebuild Maj Eqp	3,231,520
6	T/CSP/CORRIDOR: REPL 3-138	2,358,878
7	T/CSP/Beatty Road: Repl 5-138	1,448,570
8	T/OP/Canton Trans Work	1,114,651
9	TL/OPC/Mt Vernon 69kV Line	3,100,900
10	TL/OPCO/East Lima Sterling 138	1,563,242
11	TL/CSP/COLE-BEATTY-HAYDEN TAP	1,477,529
12	DS/CSP/WEST-NEW SITE D FERC	2,801,673
13	T/OP/ Ohio Power Trans Wrk	5,174,043
14	T/OH/CSP-T Work	-1,281,539
15	ALR Project and Security Inst	1,440,439
16	Waterford HGP Parts	4,333,592
17	ML0-Conners Run Expansion	7,953,190
18	WS-CI-OPCo-G PPB	35,712,884
19	ET-CI-OPCo-T ASSET IMP	8,753,248
20	ET-CI-CSPCo-T ASSET IMP	1,633,358
21	Ed-Ci-Opco-D Ast Imp	3,346,550
22	Ed-Ci-Cspco-D Ast Imp	1,743,918
23	Ed-Ci-Opco-D Cust Serv	2,119,775
24	ET-CI-OPCo-T Drvn D Asset Imp	1,894,122
25	Other Minor Projects Under $1,000,000	50,180,357
26		
27		
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42		
43	TOTAL	354,496,915

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

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

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

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	5,978,093,131	5,978,043,786	49,345	
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	490,269,865	490,269,865		
4	(403.1) Depreciation Expense for Asset Retirement Costs	12,055,617	12,055,617		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing				
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):	960	-226	1,186	
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	502,326,442	502,325,256	1,186	
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	182,968,614	182,968,614		
13	Cost of Removal	40,507,369	40,507,369		
14	Salvage (Credit)	19,955,765	19,955,765		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	203,520,218	203,520,218		
16	Other Debit or Cr. Items (Describe, details in footnote):	272,030,585	272,030,585		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	6,548,929,940	6,548,879,409	50,531	
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	4,024,027,580	4,024,027,580		
21	Nuclear Production				
22	Hydraulic Production-Conventional	78,355,716	78,355,716		
23	Hydraulic Production-Pumped Storage				
24	Other Production	145,880,258	145,880,258		
25	Transmission	817,203,711	817,153,180	50,531	
26	Distribution	1,391,679,118	1,391,679,118		
27	Regional Transmission and Market Operation				
28	General	91,783,557	91,783,557		
29	TOTAL (Enter Total of lines 20 thru 28)	6,548,929,940	6,548,879,409	50,531	

Schedule Page: 219 Line No.: 8 Column: c

Depreciation expense on asbestos ARO	$ 8,000
Depreciation expense on incremental Monongahela costs	14,710
Adjustment for Bell Howell Inserter depreciation expense billed by AEPSC	-22,936
TOTAL	$ -226

Schedule Page: 219 Line No.: 8 Column: d

Depreciation expense on account 105 assets	$1,186

Schedule Page: 219 Line No.: 13 Column: c

Includes $20,032,021 of removal cost in retirement work in progress (RWIP).

Schedule Page: 219 Line No.: 14 Column: c

Includes ($2,402,439) of salvage charges in retirement work in progress (RWIP).

Schedule Page: 219 Line No.: 16 Column: c

ARO Reserve in account 1080013	$ -76,351
Conesville U3 NBV in account 4265002	1,139,821
Reserve transferred between accounts 108, 111,122 and 124	-60,916
Reserve for Impaired Plants - Beckjord, Kammer, Muskingum River U1-4 and Sporn U2 & 4, Picway	271,028,031
TOTAL	$272,030,585

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio 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	CARDINAL OPERATING COMPANY:			
2	Advances - Open Account			130,476
3	250 Shares Common Stock	01/01/68		250
4	Subtotal			130,726
5				
6	CENTRAL COAL COMPANY:			
7	1,500 Shares Common Stock	01/01/48		603,868
8	Subtotal			603,868
9				
10	CONESVILLE COAL PREPARATION COMPANY			
11	Common Stock			109,000
12	Premium on Capital Stock			668,589
13	Equity - Undistributed Earnings			2,204,800
14	Investment in Subsidiary AOCI			-5,551,659
15	Subtotal			-2,569,270
16				
17				
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40				
41				
42	Total Cost of Account 123.1 $ -1,804,458		TOTAL	-1,834,676

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
		130,476		2
		250		3
		130,726		4
				5
				6
		603,868		7
		603,868		8
				9
				10
		109,000		11
		668,589		12
		2,204,800		13
		-5,521,441		14
		-2,539,052		15
				16
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				39
				40
				41
		-1,804,458		42

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)	252,654,805	315,658,014	Electric
2	Fuel Stock Expenses Undistributed (Account 152)	10,230,746	13,182,324	Electric
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	44,900,534	55,106,749	Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	124,074,819	100,900,895	Electric
8	Transmission Plant (Estimated)	991,190	1,602,775	Electric
9	Distribution Plant (Estimated)	2,341,340	2,992,476	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	274,275	223,854	Electric
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	172,582,158	160,826,749	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
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)	435,467,709	489,667,087	

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

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

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	740,132.00	29,879,921	318,467.00	6,347,938
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	AEP System Pool	14,443.00	912,934		
10	Appalachian Power Company	3,457.00	2,198,790		
11	Buckeye Power Inc.	22,610.00			
12					
13					
14	Other				
15	Total	40,510.00	3,111,724		
16					
17	Relinquished During Year:				
18	Charges to Account 509	149,822.00	14,742,770		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22	Appalachian Power Company	23,969.00	1,450,934		
23	Indiana Michigan Power Co	15,837.00	958,674		
24	Kentucky Power Company	19,019.00	1,151,292		
25					
26					
27	Other				
28	Total	58,825.00	3,560,900		
29	Balance-End of Year	571,995.00	14,687,975	318,467.00	6,347,938
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)		42,054,188		
33	Net Sales Proceeds (Other)				
34	Gains		7,537,909		
35	Losses		1,788,774		
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year	4,112.00		4,128.00	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	4,112.00			
40	Balance-End of Year			4,128.00	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)		2,774		
45	Gains		2,774		
46	Losses				

Name of Respondent Ohio 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

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.
350,555.00	12,759,081	286,748.00		7,470,049.00		9,165,951.00	48,986,940	1
								2
								3
				350,748.00		350,748.00		4
								5
								6
								7
								8
						14,443.00	912,934	9
						3,457.00	2,198,790	10
						22,610.00		11
								12
								13
								14
						40,510.00	3,111,724	15
								16
								17
						149,822.00	14,742,770	18
								19
								20
								21
						23,969.00	1,450,934	22
						15,837.00	958,674	23
						19,019.00	1,151,292	24
								25
								26
								27
						58,825.00	3,560,900	28
350,555.00	12,759,081	286,748.00		7,820,797.00		9,348,562.00	33,794,994	29
								30
								31
							42,054,188	32
								33
							7,537,909	34
							1,788,774	35
3,241.00		3,241.00		195,807.00		210,529.00		36
				6,482.00		6,482.00		37
								38
				3,241.00		7,353.00		39
3,241.00		3,241.00		199,048.00		209,658.00		40
								41
								42
								43
					529		3,303	44
					529		3,303	45
								46

Name of Respondent Ohio 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

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	80,717.00	833,047	67,331.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	2,980.00			
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	Net Purchase Accruals/Rev	477.00	-992,189		
10	Virginia Electric & Power	500.00	25,250		
11	Buckeye Power Company	1,653.00	791,829		
12					
13					
14	Other				
15	Total	2,630.00	-175,110		
16					
17	Relinquished During Year:				
18	Charges to Account 509	44,031.00	-329,548	2,300.00	
19	Other:				
20	Joint Plant & Consumption				
21	Cost of Sales/Transfers:				
22	Allegheny Energy Supply	2,000.00	204,938		
23	Koch Supply & Trading	500.00	96,148		
24	PPL EnergyPlus LLC	4,000.00	52,088		
25	Associated Electric Coop	2,000.00	25,285		
26	Entergy Louisiana LLC	1,273.00	16,621		
27	Other	20,348.00	58,966		
28	Total	30,121.00	454,046		
29	Balance-End of Year	12,175.00	533,439	65,031.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)		747,085		
34	Gains		613,379		
35	Losses		329,099		
	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
Ohio 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		2015		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
67,331.00						215,379.00	833,047	1
								2
								3
						2,980.00		4
								5
								6
								7
								8
						477.00	-992,189	9
						500.00	25,250	10
						1,653.00	791,829	11
								12
								13
								14
						2,630.00	-175,110	15
								16
								17
						46,331.00	-329,548	18
								19
								20
								21
						2,000.00	204,938	22
						500.00	96,148	23
						4,000.00	52,088	24
						2,000.00	25,285	25
						1,273.00	16,621	26
						20,348.00	58,966	27
						30,121.00	454,046	28
67,331.00						144,537.00	533,439	29
								30
								31
								32
							747,085	33
							613,379	34
							329,099	35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								46

Schedule Page: 229 Line No.: 27 Column: a

Cost if Sales/Transfers: Other

	Current Year Number	Current Year Amount
Associated Electric Cooperative, Inc.	6,500	713
Brownsville Public Utilities Board	170	0
Central Iowa Power Cooperative	100	11
Constellation Energy Commodities	2,900	4,909
Detroit Edison Company	500	55
DTE Stoneman, LLC	19	0
Element Markets, LLC	730	3
Entergy Louisiana	856	94
Entergy Mississippi, Inc.	1,108	125
Koch Supply & Trading	2,250	11,823
Louisville Gas and Electric	275	2,580
Northeast Texas Electri Coop	141	0
PPL EnergyPlus, LLC	2,500	9,549
Prairie Power, Inc.	5	0
Central Iowa Power Cooperative	50	670
Entergy Arkansas, Inc.	1,020	12,895
Entergy Mississippi, Inc.	1,224	15,539
Total	**20,348**	**58,966**

Name of Respondent Ohio 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

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

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

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

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

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

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	Buckeye-Northridge 34.5kv Impact	1,619	186	(5,000)	186
3	Buckeye-Rolling Meadows 34.5kv	1,933	186	(5,000)	186
4	Buckeye-Bradrick 34.5kv Impact	1,329	186		
5	Buckeye-Hauss Cridersville 69kv	857	186		
6	Buckeye Pwr-Biers Run 69kv Impact	15,035	186	(12,000)	186
7	Buckeye Pwr-Blue Creek 345kv	2,265	186		
8	Buckeye Pwr-Clear Creek 69kv	5,409	186	(5,000)	186
9	Buckeye Pwr-Marathon 69kv Study	10,056	186	(6,000)	186
10	Buckeye Pwr-Renrock 69kv Impact	7,452	186	(5,000)	186
11	Buckeye Pwr-Powhattan 69kv Impact	1,509	186	(5,000)	186
12	Buckeye Pwr-Stacy 69kv Impact	1,788	186	(5,000)	186
13	Buckeye Pwr-Stuart Chase 69kv	7,424	186		
14	Buckeye Pwr-Cumberland 34.5kv	6,495	186	(5,000)	186
15	Buckeye Pwr-New Beechwood 138kv	6,547	186	(3,000)	186
16	Buckeye-W Millersport 138kv Impact	1,208	186		
17	Buckeye-Ware 138kv Impact	14,544	186		
18	DP&L-Marysville 345/69kv Impact	10,724	186	(5,000)	186
19	N42-Mountaineer-Belmont 765kv	39,177	186		
20	PJM-#U1-060 E Lima-S Kenton 138kv	8,448	186	(8,797)	186
21	**Generation Studies**				
22					
23					
24					
25					
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

Transmission Service and Generation Interconnection Study Costs (continued)

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-#U4-028 Fostoria-Greenlawn	4,510	186	(1,781)	186
3	PJM-#U4-029 Fostoria-Greenlawn	782	186		
4	PJM-#V1-010 Howard-Fostoria 138kv	1,906	186	(1,906)	186
5	PJM-#V2-001 Howard-Bucyrus 138kv	839	186	(841)	186
6	PJM-#V4-010 Fremont-Tiffin 138kv			(360)	186
7	PJM-#V4-015 Fostoria Central 138kv	13,681	186	(5,678)	186
8	PJM-#W1-002 Tiltonsville-Windsor	149	186	(150)	186
9	PJM-#W2-007 East Leipsic 138kv	1,891	186		
10	PJM-#W2-068 Bluff Point 138kv	784	186	(784)	186
11	PJM-#W3-085 Chatfield-S Tiffin	1,430	186	(1,416)	186
12	PJM-#W3-088 SW Lima 345kv Impact	3,470	186	(3,470)	186
13	PJM-#W3-127 Columbus 14.4kv Study	665	186	(2,120)	186
14	PJM-#W3-128 Sporn-Waterford Study	867	186	(867)	186
15	PJM-#W3-128 Sporn-Waterford Impact	18,419	186	(7,867)	186
16	PJM-#W4-021A Howard 138kv Impact	16,470	186	(16,472)	186
17	PJM-#W4-021A Richland & Crawford	144	186	(1,158)	186
18	PJM-#X1-027 Hanging Rock 138kv	1	186	(1,097)	186
19	PJM-#X3-021 (MECS-PJM) 660MW	1,204	186	(1,204)	186
20	PJM-#X3-023 S Greenwich-Willard	17,002	186	(15,678)	186
21	**Generation Studies**				
22					
23					
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

Transmission Service and Generation Interconnection Study Costs (continued)

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-#X3-030 Shelby 345kv Study	1,311	186	(1,348)	186
3	PJM-#X3-030 Shelby 345kv Impact	45	186	(45)	186
4	PJM-#X3-051 Flatlick 765kv Impact	23,644	186	(13,270)	186
5	PJM-#X3-097 (AMIL-PJM) 614MW	1,481	186	(1,481)	186
6	PJM-#X3-098 (AMIL-PJM) 582MW	1,561	186	(1,561)	186
7	PJM-#X4-003 Mill Creek-Riverview	3,263	186	(3,032)	186
8	PJM-#X4-003 Mill Creek-Riverview	12,400	186	(1,730)	186
9	PJM-#X4-025 Milbrook Park 138kv	1,899	186	(1,676)	186
10	PJM-#Y1-018 Conesville #5 345kv	1,148	186	(231)	186
11	PJM-#Y1-019 Conesville #6 345kv	608	186	(456)	186
12	PJM-#Y1-030 Forest 69kv Impact	2,445	186	(2,024)	186
13	PJM-#Y1-063 Trenton 34.5kv Study	8,596	186	(8,596)	186
14	PJM-#Y1-064 Berkshire 34.5kv Study	8,426	186	(8,426)	186
15	PJM-#Y2-050 Carroll 345kv Study	919	186	(271)	186
16	PJM-#Y2-057 Wyandot 13kv Study	152	186	(152)	186
17	PJM-#Y2-085 Canton Central-Tidd	108	186		
18					
19					
20					
21	**Generation Studies**				
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Name of Respondent Ohio 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	SFAS 109 Deferred FIT	172,590,653	92,453,137	Various	93,995,158	171,048,632
2						
3	SFAS 109 Deferred SIT	20,412,947	11,373,106	Various	10,502,817	21,283,236
4						
5	SFAS 112 Post Employment Benefits	8,669,172		2283	1,011,422	7,657,750
6						
7	Unrealized Loss on Forward Committments	9,930,038	36,571,058	244, 254	45,691,518	809,578
8						
9	Deferred Distribtuion Storm Expense	8,374,775	64,548,897	593	11,095,604	61,828,068
10	- Case No. 11-346-EL-SSO					
11	- Case No. 11-348-EL-SSO					
12	- Case No. 11-351-EL-AIR					
13	- Case No. 11-352-EL-AIR					
14						
15	BridgeCo TO Funding	1,918,667		4073	166,842	1,751,825
16	- Per FERC Docket No AC04-101-000					
17	- Amortization period - 1/2005 to 12/2019					
18						
19	PJM Integration Program	2,560,137		4073	789,415	1,770,722
20	- Per FERC Docket No EL05-74-000					
21	- Amortization period - 1/2005 to 12/2014					
22						
23	Other PJM Integration	1,718,265		4073	149,403	1,568,862
24	- Per FERC Docket No AC04-101-000					
25	- Amortization period - 1/2005 to 12/2019					
26						
27	Carry Chgs-RTO Start-up Costs	1,441,084	689,315	4073	902,594	1,227,805
28	- Per FERC Docket No AC04-101-000 and EL05-74-000					
29	- Amortization period - 1/2005 up to 12/2019					
30						
31	Alliance RTO Deferred Expense	1,351,352		4073	117,473	1,233,879
32	- Per FERC Docket No AC04-101-000					
33	- Amortization period - 1/2005 to 12/2019					
34						
35	Unrecovered Fuel Cost	466,176,891	65,596,765	501	61,346,603	470,427,053
36	- Ohio ESP - Case No. 08-918-EL-SSO					
37	- Ohio ESP - Case No. 08-917-EL-SSO					
38						
39	Carrying Charges-Ohio Fuel Adjustment Clause	86,897,761	30,955,426	Various	16,861,473	100,991,714
40	- Ohio ESP - Case No. 08-918-EL-SSO					
41	- Ohio ESP - Case No. 08-917-EL-SSO					
42						
43						
44	TOTAL	1,357,975,634	812,741,719		761,321,481	1,409,395,872

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	Deferred Equity Carrying Charges - Ohio FAC	(46,466,748)	9,014,484	1823	15,371,208	-52,823,472
2	- Ohio ESP - Case No. 08-918-EL-SSO					
3	- Ohio ESP - Case No. 08-917-EL-SSO					
4						
5	Under-Recovered Ohio TCR Rider	28,403,984	30,976,957	566	11,431,774	47,949,167
6	- Docket No. 05-1194-EL-UNC					
7						
8	Carrying Charge Under Recovered Ohio TCR Rider		1,441,300			1,441,300
9	- Docket No. 05-1194-EL-UNC					
10						
11	SFAS 158 Employers' Accounting for Defined					
12	Benefit Pension and Other Postretirement Plans	389,712,336	309,686,320	2283	389,714,251	309,684,405
13						
14	Under Recovered ESRP Costs-OH	4,453,872	10,902,039	593	14,798,652	557,259
15	- ESRP-Enhanced Service Reliability Plan					
16	- Ohio ESP - Case No. 08-918-EL-SSO					
17	- Ohio ESP - Case No. 08-917-EL-SSO					
18						
19	EDR Deferral	10,012,271	13,292,478	555	20,404,495	2,900,254
20	- EDR - Economic Development Rider					
21	- Case No. 09-119-EL-AEC					
22	- Case No. 09-516-EL-AEC					
23	- Case No. 08-884-EL-AEC					
24	- Case No. 10-3066-EL-AEC					
25						
26	EDR Carrying Charges	1,726,207	1,874,609	254, 421	1,013,111	2,587,705
27	- EDR - Economic Development Rider					
28	- Case No. 09-119-EL-AEC					
29	- Case No. 09-516-EL-AEC					
30	- Case No. 08-884-EL-AEC					
31	- Case No. 10-3066-EL-AEC					
32						
33	EDR Excess Cap Deferral	12,000,000				12,000,000
34	- EDR - Economic Development Rider					
35	- Case No. 09-119-EL-AEC					
36						
37	EDR Excess Cap Deferral Carrying Charges	571,980	640,800			1,212,780
38	- EDR - Economic Development Rider					
39	- Case No. 09-119-EL-AEC					
40						
41						
42						
43						
44	TOTAL	1,357,975,634	812,741,719		761,321,481	1,409,395,872

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio 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	PWO Deferred Asset	3,400,000		4265	995,122	2,404,878
2	- PWO - Partnership With Ohio					
3	- Case No. 11-352-EL-AIR					
4	- Amortization periods - 1/2012 up to 05/2015					
5						
6	DARR Distibution Deferred Assets	86,447,400	2,530,925	Various	13,137,857	75,840,468
7	- DARR - Deferred Asset Recovery Rider					
8	- Case No. 11-352-EL-AIR					
9	- Amortization periods - 1/2012 up to 12/2018					
10						
11	DARR Carrying Charges	240,337,564		1823, 4073	29,360,643	210,976,921
12	- DARR - Deferred Asset Recovery Rider					
13	- Case No. 11-352-EL-AIR					
14	- Amortization periods - 1/2012 up to 12/2018					
15						
16	DARR Unrecognized Equity Carrying Charges	(153,511,037)	18,732,843			-134,778,194
17	- DARR - Deferred Asset Recovery Rider					
18	- Case No. 11-352-EL-AIR					
19	- Amortization periods - 1/2012 up to 12/2018					
20						
21	Deferred Equity Carrying Chgs-Non Fuel	(1,153,937)	194,820			-959,117
22	- Amortization periods - 1/2005 up to 12/2019					
23						
24	DIR Under-Recovery		2,307,334	Various	524,366	1,782,968
25	- DIR - Distribution Investment Rider					
26	- Case No. 11-346-EL-SSO					
27	- Case No. 11-348-EL-SSO					
28						
29	Dist Decoup Rev Prog Under-Recovery		20,497,457	440, 442	4,299,143	16,198,314
30	- Distribution Decoupling Revenue Program					
31	- Case No. 11-351-EL-AIR					
32	- Case No. 11-352-EL-AIR					
33						
34	Under-Recovery Capacity Cost		81,912,529	Various	16,638,923	65,273,606
35	-Case No. 10-2929-EL-UNC					
36	- Case No. 11-346-EL-SSO					
37	- Case No. 11-348-EL-SSO					
38						
39	Capacity Cost Carrying Charges		544,360			544,360
40	-Case No. 10-2929-EL-UNC					
41	- Case No. 11-346-EL-SSO					
42	- Case No. 11-348-EL-SSO					
43						
44	TOTAL	1,357,975,634	812,741,719		761,321,481	1,409,395,872

Name of Respondent Ohio 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	DIR Unrecognized Equity			1823, 254	478,905	-478,905
2	- DIR - Distribution Investment Rider					
3	- Case No. 11-346-EL-SSO					
4	- Case No. 11-348-EL-SSO					
5						
6	Def OH Auction Exp - Incremental		28,709			28,709
7						
8	Uncoll-EDR Delayed Pmt Arngmnt		5,453,342			5,453,342
9	-Uncollectible EDR Delayed Payment Arrangement					
10	- Case No. 09-119-EL-AEC					
11						
12	Load Factor Prov Under-Recovery		522,709	Various	522,709	
13	- Load Factor Provision					
14	- Case No. 11-346-EL-SSO					
15	- Case No. 11-348-EL-SSO					
16						
17						
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42						
43						
44	TOTAL	1,357,975,634	812,741,719		761,321,481	1,409,395,872

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	Allowances	105,953	3,618,598	Various	3,710,211	14,340
2						
3	Deferred Expenses	2,321,757	14,954,354	Various	16,707,926	568,185
4						
5	Deferred Property Taxes	226,349,491	224,255,676	Various	220,405,837	230,199,330
6						
7	Cook Coal Terminal - Opr Exp	712,234	6,923,246	930.2	7,332,964	302,516
8						
9	Real Estate Subsidence	728,150				728,150
10						
11	Agency Fees - Factored A/R	6,933,894	63,667,822	Various	64,588,211	6,013,505
12						
13	Defrd Property Tax - Cap Leases	5,252	491,685	236/4081	492,934	4,003
14						
15	Estimated Barging Bills	93,009	73,786,230	Various	73,879,239	
16						
17	Defrd Cook Coal Term Lease Exp	140,688		931	46,896	93,792
18						
19	MDD-Railcar Lease Exp		5,977,107	Various	5,846,782	130,325
20						
21	Unamortized Credit Line Fees	2,766,059	114,947	431, 146	1,579,846	1,301,160
22	Amortized through July 2016					
23						
24	Defd Depr&Capcty Portion -Affl	11,044,262	202,764			11,247,026
25						
26	Deferred Expenses - Current	357,086	1,752,005	Various	2,103,319	5,772
27						
28	Liquidated Rail Damages	4,024,600	18,573,467	Various	20,646,117	1,951,950
29						
30	SCR Catalyst Modules		134,400			134,400
31						
32	Def Lease Assets - Non Taxable	114,791	1,390,441	Various	598,773	906,459
33						
34						
35						
36						
37						
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39						
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41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress	1,181,952				4,646,388
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	256,879,178				258,247,301

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

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

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	Contributions in Aid of Construction	21,450,798	25,097,783
3	Accrued Book ARO Expense - SFAS 143	82,811,800	92,579,028
4	Deferred State Income Taxes	33,417,694	47,259,908
5	Interest Expense Capitalized for Tax	88,283,287	91,066,681
6	SFAS 106 Post Retirement Expenses	25,336,044	25,131,859
7	Other	162,143,458	78,437,542
8	TOTAL Electric (Enter Total of lines 2 thru 7)	413,443,081	359,572,801
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify) Nonutility, SFAS 109, 87 & 133	152,218,832	138,026,163
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	565,661,913	497,598,964

Notes

	(b)	(c)
Nonutility Items - 190.2	43,464,357	46,671,811
SFAS 109 - 190.3 & 190.4	(165,851)	439,209
SFAS 87 - 190.0009 & 190.0016	107,775,264	90,273,201
SFAS 133 - 190.0006	1,145,062	641,942
Total Line 17	152,218,832	138,026,163

Reconciliation of details applicable to Account 190, Line 18, Columns (b) and (c):

Balance at Beginning of Year	$565,661,913
(Less) Amounts Debited to:	
(a) Account 410.1	(123,490,137)
(b) Account 410.2	(14,915,652)
(c) Various	(187,622,872)
(Plus) Amounts Credited to:	
(a) Account 409.3	0
(b) Account 411.1	94,309,366
(c) Account 411.2	7,278,274
(d) Various	156,378,072
Balance at End of Year	$497,598,964

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	40,000,000		
2				
3	Total Common	40,000,000		
4				
5				
6	Preferred Stock: None			
7				
8	Total Preferred			
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

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)	
27,952,473	321,201,454					1
						2
27,952,473	321,201,454					3
						4
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio 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	208 - Donations Received from Stockholders	1,081,035,096
2	Subtotal	1,081,035,096
3		
4		
5		
6	209 - Reduction in Par or Stated Value of Capital Stock: NONE	
7	Subtotal	
8		
9		
10		
11	210 - Gain on Resale or Cancellation of Reacquired Capital Stock	-3,057,087
12	Subtotal	-3,057,087
13		
14		
15		
16	211 - Miscellaneous Paid-in Capital	
17	Recorded in connection with merger of Central Ohio Light and	
18	Power Company with respondent in 1955	168,748
19	Overestimated costs of financing	196,599
20	Preferred Stock redemption gains due to implementation of SFAS150	1,193,926
21	Recorded in connection with merger of Columbus Southern Power	
22	Company with respondent in 2011:	
23	201 - Common Stock Issued Affiliated	41,026,065
24	207 - Premium on Common Stock	257,892,418
25	208 - Donations Received from Stockholders	332,200,000
26	210 - Gain on Resale or Cancelled Reacquired Capital Stock	-1,433,630
27	211 - Miscellaneous Paid-in Capital	-7,746,484
28	Subtotal	623,497,642
29		
30		
31		
32		
33		
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37		
38		
39		
40	TOTAL	1,701,475,651

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

CAPITAL STOCK EXPENSE (Account 214)

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

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1		
2		
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19		
20		
21		
22	TOTAL	

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 221 - BONDS:		
2	NONE		
3	Total FERC 221:		
4			
5	ACCOUNT - 222 - REACQUIRED BONDS		
6			
7	Marshall County Series F Bonds, Variable Rate Due 04/2022	-35,000,000	
8			
9	Marshall County Series E Bonds, Variable Rate Due 06/2022	-50,000,000	
10			
11	Ohio Air Quality Development Series 2005A, Variable Rate Due 01/2029	-54,500,000	
12			
13	Ohio Air Quality Development Series 2005B, Variable Rate Due 07/2028	-54,500,000	
14			
15	Ohio Air Quality Development Series 2005C, Variable Rate Due 04/2028	-54,500,000	
16			
17	Ohio Air Quality Development Series 2005D, Variable Rate Due 10/2028	-54,500,000	
18			
19	WV Economic Development Mitchell Series 2008A, Variable Rate Demand Note Due 4/2036	-65,000,000	
20			
21	WV Economic Development Sporn Series 2008C, Variable Rate Demand Note Due 07/2014	-50,000,000	
22			
23	Ohio Air Quality Revenue Bond Series 2007A, Variable Rate Due 08/2040	-44,500,000	
24			
25	Total FERC 222:	-462,500,000	
26			
27	ACCOUNT 223 - ADVANCES FROM ASSOC COMPANIES		
28			
29	Fixed Rate Promissory Notes Payable to Parent		
30	5.250% Due 06/2015	200,000,000	
31			
32	Total FERC 223:	200,000,000	
33	TOTAL	4,062,325,000	47,182,232

Name of Respondent Ohio 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)

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 224 - OTHER LONG-TERM DEBT		
2			
3	Installment Purchase Contracts:		
4			
5	Ohio Air Quality Revenue Bonds 5.10% Series 2007B Due 11/2042	56,000,000	1,101,717
6	*Bond subject to mandatory tender for purchase (puttable) on 05/01/13		
7			
8	Ohio Air Quality Revenue Bonds 3.875% Series 2009A Due 12/2038	60,000,000	656,061
9	*Bond subject to mandatory tender (puttable) on 06/01/14		
10			
11	Ohio Air Quality Revenue Bonds 5.80% Series 2009B Due 12/2038	32,245,000	446,770
12			
13	Ohio Air Quality Revenue Bonds 5.15% Series C Due 05/2026	50,000,000	998,500
14			
15	Marshall County Series F, Variable Rate Due 04/2022	35,000,000	163,995
16			
17	Marshall County Series E, Variable Rate Due 06/2022	50,000,000	425,000
18			
19	Mitchell Series 2007A, 4.90% due 06/2037	65,000,000	581,256
20			
21	Ohio Air Quality Development Series 2005A, Variable Rate Due 01/2029	54,500,000	300,438
22			
23	Ohio Air Quality Development Series 2005B, Variable Rate Due 07/2028	54,500,000	300,438
24			
25	Ohio Air Quality Development Series 2005C, Variable Rate Due 04/2028	54,500,000	300,437
26			
27	Ohio Air Quality Development Series 2005D, Variable Rate Due 10/2028	54,500,000	300,437
28			
29	WV Economic Development Amos Series 2010A, 3.125% Due 03/2043	86,000,000	688,792
30	*Bond subject to mandatory tender for purchase (puttable) on 04/01/15		
31			
32			
33	TOTAL	4,062,325,000	47,182,232

Name of Respondent Ohio 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)

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	Ohio Air Quality Development Authority Cardinal Series 2010A, 3.25% Due 06/2041	79,450,000	984,190
2	*Bond subject to mandatory tender for purchase (puttable) on 06/02/14		
3			
4	Ohio Air Quality Development Authority Gavin Series 2010A, 2.875% Due 12/2027	39,130,000	542,989
5	*Bond subject to mandatory tender for purchase (puttable) on 08/01/14		
6			
7	Ohio Air Quality Revenue Bonds, 4.85% Series 2007A Due 08/2040	44,500,000	928,466
8	*Bond subject to mandatory tender for purchase (puttable) on 05/01/12		
9			
10	WV Economic Development Mitchell Series 2008A, Variable Rate Demand Note Due04/2036	65,000,000	332,083
11			
12	WV Economic Development Kammer Series 2008B, Variable Rate Demand Note Due 07/2014	50,000,000	282,353
13			
14	WV Economic Development Sporn Series 2008C, Variable Rate Demand Note Due 07/2014	50,000,000	273,786
15			
16	Ohio Air Quality Revenue Bonds Series 2007A, Variable Rate Due 08/2040	44,500,000	
17			
18	Letter of Credit Fees associated with Variable Rate Demand Notes		
19			
20	Unsecured Senior Notes:		
21			
22	5.50% Unsecured Medium Term Notes Series A Due 03/2013	250,000,000	1,625,000
23			657,500 D
24			
25	6.60% Unsecured Medium Term Notes Series B Due 03/2033	250,000,000	2,187,500
26			1,180,000 D
27			
28	5.85% Unsecured Medium Term Notes Series F Due 10/2035	250,000,000	2,187,500
29			2,815,000 D
30			
31	6.05% Unsecured Medium Term Notes Series G Due 05/2018	350,000,000	2,347,096
32			791,000 D
33	TOTAL	4,062,325,000	47,182,232

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio 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	5.50% Unsecured Medium Term Notes Series F Due 02/2013	250,000,000	1,805,904
2			647,500 D
3			
4	6.60% Unsecured Medium Term Notes Series G Due 02/2033	250,000,000	2,368,087
5			1,165,000 D
6			
7	4.85% Unsecured Medium Term Notes Series H Due 01/2014	225,000,000	1,697,821
8			184,500 D
9			
10	6.375% Unsecured Medium Term Notes Series I Due 07/2033	225,000,000	2,204,350
11			1,845,000 D
12			
13	6.00% Unsecured Medium Term Notes Series K Due 06/2016	350,000,000	2,449,572
14			1,235,500 D
15			
16	Amortization of Cash Flow Hedge on 6.00% SUN		
17			
18	5.75% Unsecured Medium Term Notes Series L Due 09/2013	250,000,000	1,676,238
19			200,000 D
20			
21	5.375% Unsecured Notes Series M Due 10/2021	500,000,000	3,682,837
22			2,065,000 D
23	Amortization of Cash Flow Hedge on 5.375% SUN		
24			
25	Floating Rate Unsecured Notes Series A Due 03/2012	150,000,000	556,619
26			
27	Total FERC 224:	4,324,825,000	47,182,232
28	Footnote:		
29			
30			
31			
32			
33	TOTAL	4,062,325,000	47,182,232

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.
						1
						2
						3
						4
						5
						6
05/05/08	04/01/22			-35,000,000	-112,575	7
						8
05/05/08	06/01/22			-50,000,000	-515,445	9
						10
01/21/05	01/01/29			-54,500,000	-199,121	11
						12
01/21/05	07/01/28			-54,500,000	-199,121	13
						14
01/21/05	04/01/28			-54,500,000	-211,868	15
						16
01/21/05	10/01/28			-54,500,000	-199,121	17
						18
06/05/08	04/01/36			-65,000,000	-95,885	19
						20
06/23/08	07/01/14			-50,000,000	-79,522	21
						22
05/01/12	08/01/40			-44,500,000	-95,563	23
						24
				-462,500,000	-1,708,221	25
						26
						27
						28
						29
02/05/04	06/01/15			200,000,000	10,500,000	30
						31
				200,000,000	10,500,000	32
				3,867,825,000	212,506,228	33

Name of Respondent Ohio 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
11/20/07	11/01/42	11/20/07	05/01/13	56,000,000	2,856,000	5
						6
						7
08/19/09	12/01/38	08/19/09	06/01/14	60,000,000	2,325,000	8
						9
						10
08/19/09	12/01/38	08/19/09	12/01/38	32,245,000	1,870,210	11
						12
05/13/99	05/01/26	05/01/99	05/01/26	50,000,000	2,575,000	13
						14
07/29/05	04/01/22	07/19/05	04/01/22	35,000,000	112,575	15
						16
12/17/03	06/01/22	12/17/03	06/01/22	50,000,000	515,445	17
						18
06/13/07	06/01/37	06/13/07	06/01/37	65,000,000	3,185,000	19
						20
01/21/05	01/01/29	01/21/05	08/18/09	54,500,000	199,121	21
						22
01/21/05	07/01/28	01/21/05	09/08/09	54,500,000	199,121	23
						24
01/21/05	04/01/28	01/21/05	09/01/09	54,500,000	211,868	25
						26
01/21/05	10/01/28	01/21/05	08/11/09	54,500,000	199,121	27
						28
03/24/10	03/01/43	03/24/10	04/01/15	86,000,000	2,687,500	29
						30
						31
						32
				3,867,825,000	212,506,228	33

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.
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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.
05/27/10	06/01/41	05/27/10	06/02/14	79,450,000	2,582,125	1
						2
						3
08/20/10	12/01/27	08/20/10	08/01/14	39,130,000	1,124,987	4
						5
						6
08/15/07	08/01/40	08/15/07	05/01/12		719,417	7
						8
						9
06/05/08	04/01/36	06/05/08	04/01/36	65,000,000	95,885	10
						11
06/23/08	07/01/14	06/23/08	07/01/14	50,000,000	73,949	12
						13
06/23/08	07/01/14	06/23/08	07/01/14	50,000,000	79,522	14
						15
05/01/12	08/01/40	05/01/12	08/01/40	44,500,000	95,563	16
						17
						18
						19
						20
						21
02/14/03	03/01/13	02/14/03	03/01/13	250,000,000	13,750,000	22
						23
						24
02/14/03	03/01/33	02/14/03	03/01/33	250,000,000	16,500,000	25
						26
						27
10/14/05	10/01/35	10/14/05	10/01/35	250,000,000	14,625,000	28
						29
						30
05/16/08	05/01/18	05/16/08	05/01/18	350,000,000	21,175,000	31
						32
				3,867,825,000	212,506,228	33

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.
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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.
02/14/03	02/15/13	02/14/03	02/15/13	250,000,000	13,750,000	1
						2
						3
02/14/03	02/15/33	02/14/03	02/15/33	250,000,000	16,500,000	4
						5
						6
07/11/03	01/15/14	07/11/03	01/15/14	225,000,000	10,912,500	7
						8
						9
07/11/03	07/15/33	07/11/03	07/15/33	225,000,000	14,343,750	10
						11
						12
06/12/06	06/01/16	06/12/06	06/01/16	350,000,000	21,000,000	13
						14
						15
					-418,450	16
						17
09/09/08	09/01/13	09/09/08	09/01/13	250,000,000	14,375,000	18
						19
						20
09/24/09	10/01/21	09/24/09	10/01/21	500,000,000	26,875,000	21
						22
					-1,679,213	23
						24
03/16/10	03/16/12	03/16/10	03/16/12		298,453	25
						26
				4,130,325,000	203,714,449	27
						28
						29
						30
						31
						32
				3,867,825,000	212,506,228	33

Schedule Page: 256 Line No.: 23 Column: a

Ohio Air Quality Revenue Bond, Variable Rate, Series 2007A, Due 08/01/2040 was repurchased on 05/01/2012 (orginally issued on 08/15/2007).

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

Ohio Air Quality Revenue Bond 5.10% Series 2007B has a Mandatory Tender Date (PUT Date) of 05/01/2013.

Schedule Page: 256.1 Line No.: 8 Column: a

Ohio Air Quality Revenue Bond 3.875% Series 2009A has a Mandatory Tender Date (PUT Date) of 06/01/2014.

Schedule Page: 256.1 Line No.: 21 Column: a

Issuance: Variable Rate,Ohio Air Quality Development,Series 2005A,Due 01/2029
Principal Amount: $54,500,000
Date of JMG Transfer: 12/15/2009
Date of Reacquisition: 08/18/2009
- Unamortized expense, premium or discount expensed at date of reacquisition.

Schedule Page: 256.1 Line No.: 23 Column: a

Issuance: Variable Rate,Ohio Air Quality Development,Series 2005B,Due 07/2028
Principal Amount: $54,500,000
Date of JMG Transfer: 12/15/2009
Date of Reacquisition: 09/08/2009
- Unamortized expense, premium or discount expensed at date of reacquisition.

Schedule Page: 256.1 Line No.: 25 Column: a

Issuance: Variable Rate,Ohio Air Quality Development,Series 2005C,Due 04/2028
Principal Amount: $54,500,000
Date of JMG Transfer: 12/15/2009
Date of Reacquisition: 09/01/2009
- Unamortized expense, premium or discount expensed at date of reacquisition.

Schedule Page: 256.1 Line No.: 27 Column: a

Issuance: Variable Rate,Ohio Air Quality Development,Series 2005D,Due 10/2038
Principal Amount: $54,500,000
Date of JMG Transfer: 12/15/2009
Date of Reacquisition: 08/11/2009
- Unamortized expense, premium or discount expensed at date of reacquisition.

Schedule Page: 256.1 Line No.: 29 Column: a

West Virginia Development Development Authority Amos Bond 3.125% Series 2010A has a Mandatory Tender Date (PUT Date) of 04/01/2015.

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

Ohio Air Quality Development Authority Cardinal Bond 3.25% Series 2010A has a Mandatory Tender Date (PUT Date) of 06/02/2014.

Schedule Page: 256.2 Line No.: 4 Column: a

Ohio Air Quality Development Authority Gavin Bond 2.875% Series 2010A has a Mandatory Tender Date (PUT Date) of 08/01/2014.

Schedule Page: 256.2 Line No.: 7 Column: a

Ohio Air Quality Revenue Bond 4.85% Series 2007A has a Mandatory Tender Date (PUT Date) of 05/01/2012, at which time it was remarketed and is currently included in reacquired bonds of the Company.

Schedule Page: 256.2 Line No.: 12 Column: a

West Virginia Economic Development Authority Kammer Bond, Variable Rate, Series 2008B, Due 07/01/2014 was remarketed on 03/01/2011 (originally issued on 06/23/2008).

Schedule Page: 256.2 Line No.: 16 Column: a

Ohio Air Quality Revenue Bond, Variable Rate, Series 2007A, Due 08/01/2040 was repurchased on 05/01/2012 (orginally issued on 08/15/2007).

Schedule Page: 256.3 Line No.: 28 Column: a

The difference between the total interest on this schedule and the total of accounts 427 and 430 is due to interest on short-term advances from the AEP Money Pool.

Name of Respondent Ohio 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

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

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

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	343,534,107
2		
3		
4	Taxable Income Not Reported on Books	
5		
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15		
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20		
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	339,000,688
28	Show Computation of Tax:	
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		

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

		In (000's)
Net Income for the year per Page 117		343,534
Federal Income Taxes		172,658
State Income Taxes		(28,140)
Pretax Book Income		488,052
Increase (Decrease) in Taxable Income resulting from:		
AFUDC / Interest Capitalized		(1,531)
Amortization of Pollution Control Equip		(65,508)
Emission Allowances (Net)		8,798
Excess Tax vs Book Depreciation		(124,239)
Mark-to-Market		(4,657)
Deferred Storm Damage		(53,453)
Pension Expenses		(20,840)
Deferred Revenue - Bonus Lease		(1,838)
Removal Costs		(27,414)
Federal and State Mitigation Programs		(2,271)
Book/Tax Unit of Property Adj		(77,137)
Book Leases Cap'd for Tax		(1,645)
Accrued ARO Expense - SFAS 143		27,906
Provision for Revenue Refunds		4,689
Capacity Cost Carrying Charges		(65,818)
Deferred Equity Carrying Charges		(10,036)
Ohio Transmission Cost Rider		13,507
Deferred Asset Recovery Rider		22,230
Medicare Subsidy		3,109
Book Loss Provision - Plant M&S		(2,335)
Deferred Fuel Costs		(18,344)
Accrued Incentive Compensation		7,919
Accrued Partnership Ohio & Ohio Growth Fund		(30,985)
Enhanced Service Reliability Plan		3,897
SFAS 112 Post Employment Benefit		(2,686)
Accrued SIT Reserve		(5,631)
Charitable Contribution Carryforward		2,747
Impaired Assets		287,027
Nondeductible Items		3,180
Other (Net)		(5,479)
Estimated Current Year Taxable Income Before State Income Tax (Separate Return Basis)		351,214
Less State Income Tax		(12,214)
Federal Taxable Income		339,000
		=======
Computation of Tax *		
Federal Income Tax on Current Year Taxable Income (Separate Return Basis) at the Statutory Rate of 35%		118,650
Adjustment due to System Consolidation	(a)	(11,915)
Estimated Tax Currently Payable	(b)	106,735
Tax Provision Adjustment		31
Adjustments of Prior Year's Accruals (Net)		(13,812)
Estimated Current Federal Income Taxes (Net)		92,954
		=======

(a) Represents the allocation of the 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 return is filed.

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	FEDERAL:					
2	INCOME TAX	-8,883,022		92,930,577	80,763,998	-17,759,808
3	FICA - 2012	2,130,046		18,663,139	18,251,071	
4	Unemployment - 2012	96,749		203,830	179,178	
5	EXCISE TAX - 2011			7,654	7,654	
6	EXCISE TAX - 2012			31,249	31,249	
7						
8	STATE OF OHIO:					
9	CAT TAX - 2011	2,679,000		202,880	2,881,880	
10	CAT TAX - 2012			10,396,850	7,723,850	
11	OCC & PUCO FEES - 2012			5,879,061	5,879,061	
12	KWH State Excise Tax - 2011	12,249,531			12,249,531	
13	KWH State Excise Tax - 2012			143,109,283	130,660,979	
14	SALES & USE - 2011	341,326	131,549	-87,882	121,895	
15	SALES & USE - 2012			1,494,608	1,315,266	
16	Unemployment - OH 2012	47,867		113,945	161,160	
17	INCOME TAX - 2000			-6,145,609	-6,145,608	
18						
19	STATE OF ILLINOIS:					
20	INCOME TAX 2011	289,508		-323,255	-33,747	
21	INCOME TAX 2012			934,214	454,047	
22	SALES & USE - 2011	13,968		-1,974	11,994	
23	SALES & USE - 2012			107,710	91,056	
24	Unemployment - IL 2012	1,310		36,847	37,703	
25						
26	STATE OF WEST VIRGINIA:					
27	INCOME TAX - 2006					
28	INCOME TAX - 2009	-7				
29	INCOME TAX - 2010					
30	INCOME TAX - 2011	-3,008,008		810,182	-2,197,826	
31	INCOME TAX - 2012			13,306,549	3,031,000	
32	STATE FRAN. 09&PRIOR	-11,884		610,117	610,117	
33	STATE FRAN. 2011	47,683		-61,721	-14,038	
34	STATE FRAN. 2012			7,676	22,101	
35	Unemployment - WV 2012	7,298		48,261	55,559	
36	SALES & USE TAX - 2011	22,419		-2,085	20,334	
37	SALES & USE TAX -2012			144,218	123,169	
38	BUS & OCCUPATION-2011	1,336,231		145,036	1,481,267	
39	BUS & OCCUPATION-2012			15,735,811	14,572,102	
40	BUS & OCCUPATION-Audit	3,327,200		327,500		
41	TOTAL	437,248,507	131,549	516,750,340	485,904,321	-19,160,029

Name of Respondent Ohio 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

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						
2						
3	LOCAL:					
4	Real & Pers-2009 OH			-7,090	-7,090	
5	Real & Pers-2010 OH	193,193,195		365,544	193,558,739	
6	Real & Pers-2011 OH	203,260,595		-1,911,810	-8,163	
7	Real & Pers-2012 OH			208,575,970		
8						
9	Re Prop-Leased 2011 OH	206,391		-4,086	203,338	
10	Re Prop-Leased 2012 OH			210,434		
11						
12	Pers Prop-Leased 2009 OH	24,933		-24,933		
13	Pers Prop-Leased 2010 OH	235,278		-217,152	18,126	
14	Pers Prop-Leased 2011 OH	448,474		-83,057	165,417	
15	Pers Prop-Leased 2012 OH			270,700		
16						
17	RE & Pers Prop-2010 WV	7,790,720			7,790,720	
18	RE & Pers Prop-2011 WV	15,438,710		-364,696	7,537,007	
19	RE & Pers Prop-2012 WV			14,180,500		
20						
21	Pers Prop-Leased 2010 WV	21,334		1,623	22,957	
22	Pers Prop-Leased 2011 WV	10,500		2,153	7,753	
23	Pers Prop-Leased 2012 WV			8,000		
24						
25	RE & Pers Prop-2010 IL	602,611			602,611	
26	RE & Pers Prop-2011 IL	575,000		55,314	630,314	
27	RE & Pers Prop-2012 IL			630,000		
28						
29	RAIL CAR PROPERTY					
30	Prop Tax - 2010	65,429		-40,912	24,517	
31	Prop Tax - 2011	68,355		26,379	85,146	
32	Prop Tax - 2012			102,523	7,502	
33						
34	2010 LA Property Tax	-2,856		2,856		
35						
36	2009 KY Property Tax	-9,071		9,071		
37	2010 KY Property Tax	38,000		-6,885	31,115	
38	2011 KY Property Tax	38,000		-2,000	34,414	
39	2012 KY Property Tax			36,500		
40						
41	TOTAL	437,248,507	131,549	516,750,340	485,904,321	-19,160,029

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						
2	CITY TAX - 2010 & Prior					
3	CITY TAX - 2011	-1,355,878		-589,037	-322,723	
4	CITY TAX - 2012			-223,135	1,137,837	
5	STATE LIC TAX 2011 &			625	625	
6	STATE LIC TAX 2012			4,784	4,784	
7	FED INC TAX FIN48					-1,400,221
8	STATE INC TAX FIN48	6,416,338		-4,608,286	699,236	
9						
10	STATE OF MICHIGAN:					
11	INCOME TAX 2011	-442,006		218,718	-223,288	
12	INCOME TAX 2012			28,596	223,288	
13						
14	Payroll Taxes - CCD			1,202,258	1,202,258	
15						
16	STATE OF KENTUCKY:					
17	INCOME TAX 2000			101	101	
18	INCOME TAX 2011	-62,760		563	-62,197	
19	INCOME TAX 2012			275,561	194,000	
20						
21	MISC FRANCHISE			-25	-25	
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	437,248,507	131,549	516,750,340	485,904,321	-19,160,029

Name of Respondent Ohio 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 (I) 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
-14,476,251		91,930,521			1,000,056	2
2,542,114		12,667,108			5,996,031	3
121,401		163,225			40,605	4
					7,654	5
		8,233			23,016	6
						7
						8
		202,880				9
2,673,000		10,396,850				10
		5,879,061				11
						12
12,448,304		143,109,283				13
		-1,790			-86,092	14
319,342	140,000	-69			1,494,677	15
652		57,984			55,961	16
-1		-6,145,609				17
						18
						19
		-283,401			-39,854	20
480,167		844,851			89,363	21
					-1,974	22
16,654					107,710	23
454					36,847	24
						25
						26
						27
-7						28
						29
		-861,595			1,671,777	30
10,275,549		20,791,301			-7,484,752	31
-11,884		610,117				32
		-61,721				33
-14,425		7,676				34
		51,171			-2,910	35
					-2,085	36
21,049		770			143,448	37
		144,162			874	38
1,163,709		15,735,811				39
3,654,700		327,500				40
448,942,948	140,000	505,480,728			11,269,612	41

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 (I) 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
						2
						3
		-7,090				4
		381,603			-16,059	5
201,356,948		200,347,858			-202,259,668	6
208,575,970					208,575,970	7
						8
-1,033		-4,086				9
210,434		210,434				10
						11
		-24,933				12
		-217,152				13
200,000		-83,057				14
270,700		270,700				15
						16
		7,239,356			-7,239,356	17
7,537,007		6,305,005			-6,669,701	18
14,180,500					14,180,500	19
						20
					1,623	21
4,900		4,552			-2,399	22
8,000		3,997			4,003	23
						24
						25
					55,314	26
630,000					630,000	27
						28
						29
		2,385			-43,297	30
9,588					26,379	31
95,021					102,523	32
						33
					2,856	34
						35
					9,071	36
		-1,682			-5,203	37
1,586		36,000			-38,000	38
36,500					36,500	39
						40
448,942,948	140,000	505,480,728			11,269,612	41

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 (I) 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
		-159,206			159,206	2
-1,622,192		-2,293,552			1,704,515	3
-1,360,972		829,228			-1,052,363	4
		625				5
		4,762			22	6
-1,400,221						7
1,108,816		-4,608,286				8
						9
						10
		183,902			34,816	11
-194,692		25,842			2,754	12
						13
		1,202,258				14
						15
						16
		101				17
		8,390			-7,827	18
81,561		248,480			27,081	19
						20
		-25				21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
448,942,948	140,000	505,480,728			11,269,612	41

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

Page 262 Line 2, Column f	23,888	Fuel Tax Credit
	(19,183,918)	NOL Carryforward/FIN 48 Reclass
	1,400,222	Tax Credit Carryforward
	(17,759,808)	

Schedule Page: 262.2 Line No.: 7 Column: f

Page 262.2, Line 7, Column f	(1,400,221)	Reclass from Account 2360001

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 Account No. (c)	Deferred for Year Amount (d)	Allocations to Current Year's Income Account No. (e)	Allocations to Current Year's Income Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%	13,492,560			4114/4115	1,849,233	
6							
7							
8	TOTAL	13,492,560				1,849,233	
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							
23							
24							
25							
26							
27							
28							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44							
45							
46							
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
			3
			4
11,643,327	Various		5
			6
			7
11,643,327			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			30
			31
			32
			33
			34
			35
			36
			37
			38
			39
			40
			41
			42
			43
			44
			45
			46
			47
			48

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

Remaining amortization period is 12 years.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio 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	Other Deferred Credits-Non Current	1,567,500	186	1,952,500	385,000	
2						
3	Allowances	6,437	Various	786,759	906,759	126,437
4						
5	Customer Advance Receipts	13,318,342	142	162,182,318	164,425,671	15,561,695
6						
7	Deferred Rev - Pole Attachments	747,438	Various	4,747,184	5,130,403	1,130,657
8						
9	IPP - System Upgrade	2,464,505				2,464,505
10						
11	SFAS 106 - OPEB	4,353,940	926	581,714	5,563	3,777,789
12						
13	ABD - Sharyland Deferred Revenue	527,179	143, 454	527,179	542,994	542,994
14						
15	Unidentified Cash Receipts	1,075	Various	250,258	254,537	5,354
16						
17	Railroad Cars Subleased Rev	2,853	Various	307,227	318,535	14,161
18						
19	Accrued Lease Exp - Non Current	451,013	931	146,244		304,769
20						
21	Other Deferred Credits - Current	1,152,374	Various	5,341,821	4,883,526	694,079
22						
23	Contract Settlement Reserves	5,489,284				5,489,284
24						
25	Federal Mitigation Deferral (NSR)				4,623,711	4,623,711
26						
27	Customer Choice Collateral Deposit	2,794,142	232	520,000	12,882,598	15,156,740
28						
29	Def Rev Selling Price Variance	29,948	9302	8,173,641	8,283,298	139,605
30						
31	Fiber Opt Lines Sold Deferred Rev	1,337,738	451	119,858		1,217,880
32	- Amortization period - 1/2005 to					
33	12/2024					
34						
35	Legal Contingencies	3,342,000				3,342,000
36						
37	Deferred Rev - Bonus Lease Curr	1,837,913				1,837,913
38						
39	Deferred Rev - Bonus Lease NC	11,027,475	421	1,837,912		9,189,563
40						
41	GridSmart Capital Reserve		588	1,759	61,209	59,450
42						
43						
44						
45						
46						
47	TOTAL	50,451,156		187,476,374	202,703,804	65,678,586

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio 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	Balance at Beginning of Year	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1	Amounts Credited to Account 411.1
	(a)	(b)	(c)	(d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities	353,460,058	28,154,769	4,957,087
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	353,460,058	28,154,769	4,957,087
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)	353,460,058	28,154,769	4,957,087
18	Classification of TOTAL			
19	Federal Income Tax	353,460,058	28,154,769	4,957,087
20	State Income Tax			
21	Local Income Tax			

NOTES

Name of Respondent Ohio 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 _ 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
						376,657,740	4
							5
							6
							7
						376,657,740	8
							9
							10
							11
							12
							13
							14
							15
							16
						376,657,740	17
							18
						376,657,740	19
							20
							21

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio 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	1,678,755,624	212,576,515	126,535,787
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	1,678,755,624	212,576,515	126,535,787
6				
7	Non Utility	592,747		
8	SFAS 109/FIN 48	102,538,988		
9	TOTAL Account 282 (Enter Total of lines 5 thru	1,781,887,359	212,576,515	126,535,787
10	Classification of TOTAL			
11	Federal Income Tax	1,781,887,359	212,576,515	126,535,787
12	State Income Tax			
13	Local Income Tax			

NOTES

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
		Various	1,529			1,764,794,823	2
							3
							4
			1,529			1,764,794,823	5
							6
	13,876			Various	1,529	580,400	7
		Various	52,334,971	Various	51,541,062	101,745,079	8
	13,876		52,336,500		51,542,591	1,867,120,302	9
							10
	13,876		52,336,500		51,542,591	1,867,120,302	11
							12
							13

NOTES (Continued)

Name of Respondent Ohio 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 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	Deferred Asset Recovery Rider	60,645,875		
4	Accrued Book Pension Expense	133,547,346	11,378,032	4,590,546
5	Deferred Fuel Expense	187,472,416	8,313,190	19,996,437
6	Mark To Market Book Gain	22,879,181	21,781,912	19,889,097
7	Deferred State Income Taxes	82,799,127	14,157,293	35,123,766
8	Other	107,927,764	120,861,324	90,273,796
9	TOTAL Electric (Total of lines 3 thru 8)	595,271,709	176,491,751	169,873,642
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other	94,095,227		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	689,366,936	176,491,751	169,873,642
20	Classification of TOTAL			
21	Federal Income Tax	586,154,862	162,334,458	134,749,876
22	State Income Tax	103,212,074	14,157,293	35,123,766
23	Local Income Tax			

NOTES

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

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
6,862,213	14,294,369					53,213,719	3
						140,334,832	4
						175,789,169	5
						24,771,996	6
				Various	7,242,400	69,075,054	7
190,526	348,292			Various	2,534,840	140,892,366	8
7,052,739	14,642,661				9,777,240	604,077,136	9
							10
							11
							12
							13
							14
							15
							16
							17
133,594	100,459,487	Various	54,686,744	Various	54,997,450	-5,919,960	18
7,186,333	115,102,148		54,686,744		64,774,690	598,157,176	19
							20
7,186,333	115,102,148		44,183,927		46,159,184	507,798,886	21
			10,502,817		18,615,506	90,358,290	22
							23

NOTES (Continued)

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

This footnote applies to both current and prior year.

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.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio 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		175, 1823	7,648,825	7,648,825	
2						
3	Ohio RSP-Low Income Customer/Econ Recovery	2,520,556	232	676,321	400,000	2,244,235
4	-Docket No. 04-169-EL-UNC					
5						
6	Carry Chg-Over Recover OH TCR	542,392	431	542,392		
7	-Docket No. 05-1194-EL-UNC					
8						
9	IGCC Pre-Construction Costs Net Recovery	3,448,543	1823	38,982	76,193	3,485,754
10	-Docket No. 05-376-EL-UNC					
11						
12	IGCC Over-Recovered Interest	747,791			177,316	925,107
13	-Docket No. 05-376-EL-UNC					
14						
15	DSM Over Recovery	19,124,332	Various	43,287,925	36,759,173	12,595,580
16	- Demand Side Management					
17	- Ohio ESP - Case No. 08-918-EL-SSO					
18	- Ohio ESP - Case No. 11-346-EL-SSO					
19	- Ohio ESP - Case No. 11-348-EL-SSO					
20	- Ohio ESP - Case No. 11-349-EL-AAM					
21	- Ohio ESP - Case No. 11-350-EL-AAM					
22						
23	Over-Recovered gSMART Misc Dist Expense	9,902,262	588	1,339,035	3,153,153	11,716,380
24	- Ohio ESP - Case No. 08-918-EL-SSO					
25						
26	Over-Recovered gSMART Debt Carrying Charge	(1,452,339)	1823	4,389,639	1,452,339	-4,389,639
27	- Ohio ESP - Case No. 08-918-EL-SSO					
28						
29	Over-Recovered gSMART Equity Carrying Charge	502,419	1823	502,419	1,723,018	1,723,018
30	- Ohio ESP - Case No. 08-918-EL-SSO					
31						
32	Over-Recovered gSMART Depr/A&G Expense	(1,448,691)	1823	5,587,206	1,448,691	-5,587,206
33	- Ohio ESP - Case No. 08-918-EL-SSO					
34						
35	GridSMART Reserve				38,585	38,585
36	- Case No. 12-509-EL-RDR					
37						
38						
39						
40						
41	TOTAL	38,553,823		99,401,152	100,309,461	39,462,132

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio 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	Over-Recovery EDR Deferral	2,422,199	555	2,422,379	180	
2	- EDR - Economic Development Rider					
3	- Case No. 09-119-EL-AEC					
4	- Case No. 09-516-EL-AEC					
5	- Case No. 08-884-EL-AEC					
6	- Case No. 10-3066-EL-AEC					
7						
8	EDR-Carrying Charge Over-Recovery	6,419	1823	19,583	13,164	
9	- EDR - Economic Development Rider					
10	- Case No. 09-119-EL-AEC					
11	- Case No. 09-516-EL-AEC					
12	- Case No. 08-884-EL-AEC					
13	- Case No. 10-3066-EL-AEC					
14						
15	Over-Recovery Monogahela Power Term	215,639	4073	16	26	215,649
16	- Case No. 05-765-EL-UNC					
17						
18	SFAS 109 Deferred FIT	2,022,301	Various	972,503	596,781	1,646,579
19						
20	Over-Recovered Fuel Costs - OH		501	21,995,065	34,499,999	12,504,934
21	- Ohio ESP - Case No. 08-918-EL-SSO					
22	- Ohio ESP - Case No. 08-917-EL-SSO					
23						
24	Over-Recovery AER Costs - OH		557	35,784	2,378,940	2,343,156
25	- Case No. 11-346-EL-SSO					
26	- Case No. 11-348-EL-SSO					
27	- Case No. 11-349-EL-AAM					
28	- Case No. 11-350-EL-AAM					
29						
30	Over-Recovered Market T Rider		Various	8,034,709	8,034,709	
31	- MTR - Market Transition Rider					
32	- Case No. 11-346-EL-SSO					
33	- Case No. 11-348-EL-SSO					
34						
35	Over-Recovered Dist Invest Rider		Various	1,908,369	1,908,369	
36	- DIR - Distribution Investment Rider					
37	- Case No. 11-346-EL-SSO					
38	- Case No. 11-348-EL-SSO					
39						
40						
41	TOTAL	38,553,823		99,401,152	100,309,461	39,462,132

Name of Respondent Ohio 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

ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	1,636,808,400	1,680,179,478
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	945,233,021	1,077,742,471
5	Large (or Ind.) (See Instr. 4)	745,568,844	983,382,876
6	(444) Public Street and Highway Lighting	18,079,470	17,649,264
7	(445) Other Sales to Public Authorities	33,169	64,879
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	3,345,722,904	3,759,018,968
11	(447) Sales for Resale	1,436,992,525	1,594,320,264
12	TOTAL Sales of Electricity	4,782,715,429	5,353,339,232
13	(Less) (449.1) Provision for Rate Refunds	2,577,000	-6,034,599
14	TOTAL Revenues Net of Prov. for Refunds	4,780,138,429	5,359,373,831
15	Other Operating Revenues		
16	(450) Forfeited Discounts	3,208,602	3,592,449
17	(451) Miscellaneous Service Revenues	7,681,845	5,338,704
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	29,427,587	30,668,766
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	971,992	-58,783
22	(456.1) Revenues from Transmission of Electricity of Others	100,193,603	56,854,297
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	141,483,629	96,395,433
27	TOTAL Electric Operating Revenues	4,921,622,058	5,455,769,264

ELECTRIC OPERATING REVENUES (Account 400)

6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
12,413,637	14,950,412	1,273,361	1,273,589	2
				3
7,037,849	10,726,112	173,948	173,091	4
11,352,291	17,698,421	10,274	10,377	5
92,832	116,208	2,784	2,792	6
396	911	26	26	7
				8
				9
30,897,005	43,492,064	1,460,393	1,459,875	10
32,625,825	30,969,182	97	116	11
63,522,830	74,461,246	1,460,490	1,459,991	12
				13
63,522,830	74,461,246	1,460,490	1,459,991	14

Line 12, column (b) includes $ 31,263,358 of unbilled revenues.

Line 12, column (d) includes -37,253 MWH relating to unbilled revenues

Schedule Page: 300 Line No.: 10 Column: b

Detail of Unmetered Sales:

	Revenue	MWH	Average Customers
Residential	6,407,048	24,542	36,628
Commercial	17,481,787	84,856	26,883
Industrial	1,546,786	8,347	1,578
Public Street Lighting	16,034,825	99,375	1,476
	41,470,446	217,120	66,565

Total Sales to Ultimate Consumers included $395,352,810 of Operating Revenue for distribution services provided to Open Acess Customers. Megawatt hours delivered to Open Acess Customers were 16,007,911 and are excluded from the reported megawatt hours sold on Pg 301 (d).

Schedule Page: 300 Line No.: 10 Column: c

Total Sales to Ultimate Consumers include $101,381,440 of Operating Revenues for distribution services provided to Open Acess Customers. Megawatt hours delivered to Open Access Customers were 4,935,606 and are excluded from the reported megawatt hours sold on Pg 301(e).

Schedule Page: 300 Line No.: 17 Column: b

Customer service revenue, including connects, reconnects, disconnects, temporary services and other charges billed to customer.

Schedule Page: 300 Line No.: 21 Column: b

Description	YTD - 2012
Assoc. Business Development	2,460,269
Off System Sales FTR Mark to Mkt	885,534
Oth Elect Rev-Transmission-Affil	267,126
Financial Trading Rev. Unrealized	(2,562,494)
All Other (under $250,000 each)	(78,443)
Total	971,992

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

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

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

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
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33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent Ohio 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

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. 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)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	440-Residential					
2	GS-1 Gen Svc Fixed	15	1,796	1	15,000	0.1197
3	GS-2 Gen Svc Low	20	2,566	1	20,000	0.1283
4	RR Residential Regular	5,936,826	734,246,642	473,117	12,548	0.1237
5	RR-1 Residential Low Usage	630,081	80,806,353	132,653	4,750	0.1282
6	RS Residential Service	5,985,701	691,971,667	501,920	11,926	0.1156
7	OL Outdoor Lighting	23,618	6,244,422			0.2644
8	OAD RR Residential Regular	738,307	37,402,133	62,471	11,818	0.0507
9	OAD RS Residential Service	1,172,299	54,939,425	103,198	11,360	0.0469
10	OAD OL Outdoor Lighting	924	162,626			0.1760
11	OAD - MWH Sold Adjustment	-2,071,752				
12	Subtotal-Billed	12,416,039	1,605,777,630	1,273,361	9,751	0.1293
13	Net Unbilled	-2,402	31,030,770			-12.9187
14	Total-Residential	12,413,637	1,636,808,400	1,273,361	9,749	0.1319
15						
16	442-Commercial					
17	EHG Electric Heating General	19,274	1,770,167	444	43,410	0.0918
18	GS-1 Gen Svc Fixed	590,852	79,138,749	101,916	5,797	0.1339
19	GS-2 Gen Svc Low	2,237,896	282,379,140	35,989	62,183	0.1262
20	GS-3 Gen Svc Medium	3,724,468	342,028,353	5,873	634,168	0.0918
21	GS-4 Gen Svc Large	581,947	32,800,917	6	96,991,167	0.0564
22	GS-TOD Gen Svc-Time of Day	74,535	7,185,330	699	106,631	0.0964
23	LS Special Contract	-9	-47,216			5.2462
24	OL Outdoor Lighting	73,447	16,346,819	1	73,447,000	0.2226
25	PB Phone Booth	9	1,576	6	1,500	0.1751
26	PS School Service	13,570	1,330,079	71	191,127	0.0980
27	SB Stand by Service		113,006	1		
28	SL Street Lighting	1,032	88,532	3	344,000	0.0858
29	TL Traffic Light	2	-435	1	2,000	-0.2175
30	TV Television Cable	5,676	638,969	133	42,677	0.1126
31	OAD GS-1 Gen Svc Fixed	79,278	3,847,461	8,998	8,811	0.0485
32	OAD GS-2 Gen Svc Low	1,600,398	59,897,817	15,051	106,332	0.0374
33	OAD GS-3 Gen Svc Medium	4,809,084	112,113,928	4,651	1,033,989	0.0233
34	OAD GS-4 Gen Svc Large	311,063	1,191,845	7	44,437,571	0.0038
35	OAD OL Outdoor Lighting	5,872	788,213			0.1342
36	OAD PB Phone Booth	10	780	6	1,667	0.0780
37	OAD PS School Service	20,536	643,223	83	247,422	0.0313
38	OAD SL Street Lighting	3,309	100,267	1	3,309,000	0.0303
39	OAD TV Television Cable	108	3,773	1	108,000	0.0349
40	OAD - MWH Sold Adjustment	-7,138,254				
41	TOTAL Billed	30,934,258	3,314,459,546	1,460,393	21,182	0.1071
42	Total Unbilled Rev.(See Instr. 6)	-37,253	31,263,358	0	0	-0.8392
43	TOTAL	30,897,005	3,345,722,904	1,460,393	21,157	0.1083

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. 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)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Net Estimated Billings	44,267	-112,397	7	6,323,857	-0.0025
2	Subtotal-Billed	7,058,370	942,248,896	173,948	40,577	0.1335
3	Net Unbilled	-20,521	2,984,125			-0.1454
4	Total-Commercial	7,037,849	945,233,021	173,948	40,459	0.1343
5						
6	442-Industrial					
7	EHG Electric Heating General	869	91,436	14	62,071	0.1052
8	GS-1 Gen Svc Fixed	19,941	3,094,220	4,969	4,013	0.1552
9	GS-2 Gen Svc Low	597,515	68,422,680	2,301	259,676	0.1145
10	GS-3 Gen Svc Medium	2,039,746	167,525,316	556	3,668,608	0.0821
11	GS-4 Gen Svc Large	5,829,199	265,949,880	31	188,038,677	0.0456
12	GS-TOD Gen Svc-Time of Day	5,937	597,101	24	247,375	0.1006
13	IR Interruptible Service	3,071,154	153,533,414	13	236,242,615	0.0500
14	OL Outdoor Lighting	7,086	1,417,961			0.2001
15	OAD EHG Electric Heating General	213	9,459	2	106,500	0.0444
16	OAD GS-1 Gen Svc Fixed	3,894	200,530	528	7,375	0.0515
17	OAD GS-2 Gen Svc Low	684,184	23,502,113	1,300	526,295	0.0344
18	OAD GS-3 Gen Svc Medium	2,534,239	50,663,020	505	5,018,295	0.0200
19	OAD GS-4 Gen Svc Large	3,243,151	12,794,185	30	108,105,033	0.0039
20	OAD OL Outdoor Lighting	559	61,240			0.1096
21	OAD - MWH Sold Adjustment	-6,771,548				
22	Company use - MWH Adj	-1,166	-118,887			0.1020
23	Net Estimated Billings	101,812	607,202	1	101,812,000	0.0060
24	Subtotal-Billed	11,366,785	748,350,870	10,274	1,106,364	0.0658
25	Net Unbilled	-14,494	-2,782,026			0.1919
26	Total-Industrial	11,352,291	745,568,844	10,274	1,104,953	0.0657
27						
28	444-Street & Highway Lighting					
29	GS-1 Gen Svc Fixed	2,967	467,652	922	3,218	0.1576
30	GS-2 Gen Svc Low	1,227	135,075	15	81,800	0.1101
31	GS-3 Gen Svc Medium	878	75,203	1	878,000	0.0857
32	OL Outdoor Lighting	207	45,661			0.2206
33	SL Street Lighting	77,718	14,170,437	1,104	70,397	0.1823
34	TL Traffic Light	10,590	1,157,799	71	149,155	0.1093
35	OAD GS-1 Gen Svc Fixed	1,925	144,371	523	3,681	0.0750
36	OAD GS-2 Gen Svc Low	1,023	37,535	14	73,071	0.0367
37	OAD GS-3 Gen Svc Medium	185	5,577	1	185,000	0.0301
38	OAD OL Outdoor Lighting	16	4,076			0.2548
39	OAD SL Street Lighting	21,071	1,760,537	118	178,568	0.0836
40	OAD TL Traffic Light	1,188	43,199	15	79,200	0.0364
41	TOTAL Billed	30,934,258	3,314,459,546	1,460,393	21,182	0.1071
42	Total Unbilled Rev.(See Instr. 6)	-37,253	31,263,358	0	0	-0.8392
43	TOTAL	30,897,005	3,345,722,904	1,460,393	21,157	0.1083

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

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. 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)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	OAD - MWH Sold Adjustment	-26,357				
2	Subtotal-Billed	92,638	18,047,122	2,784	33,275	0.1948
3	Net Unbilled	194	32,348			0.1667
4	Total-St & Highway Lighting	92,832	18,079,470	2,784	33,345	0.1948
5						
6	A/C 445 Pub Authorities - Other					
7	FP Flood Pumping	426	35,028	26	16,385	0.0822
8	Subtotal-Billed	426	35,028	26	16,385	0.0822
9	Net Unbilled	-30	-1,859			0.0620
10	Total-Pub Authorities - Other	396	33,169	26	15,231	0.0838
11						
12	Fuel Adj Clause - Footnote					
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	30,934,258	3,314,459,546	1,460,393	21,182	0.1071
42	Total Unbilled Rev.(See Instr. 6)	-37,253	31,263,358	0	0	-0.8392
43	TOTAL	30,897,005	3,345,722,904	1,460,393	21,157	0.1083

Schedule Page: 304.2 Line No.: 12 Column: a

Fuel Adjustment Clause - Total Estimated Additional Revenues Billed and Unbilled

440-Residential	Revenues
GS-1 Gen Svc Fixed	567
GS-2 Gen Svc Low	630
RR Residential Regular	235,010,801
RR-1 Residential Low Usage	24,072,637
RS Residential Service	208,528,361
OL Outdoor Lighting	872,037
OAD Residential Regular	11
OAD Residential Service	(8)
Subtotal-Billed	**468,485,036**
Net Unbilled	(5,416,808)
Total 440-Residential	**463,068,228**

442-Commerical	Revenues
EHG Electric Heating General	584,693
GS-1 Gen Svc Fixed	19,729,608
GS-2 Gen Svc Low	82,205,917
GS-3 Gen Svc Medium	137,693,716
GS-4 Gen Svc Large	22,098,116
GS-TOD Gen Svc-Time of Day	2,590,123
LS Special Contract	(319)
OL Outdoor Lighting	2,743,410
PB Phone Booth	365
PS School Service	472,396
SB Stand by Service	604
SL Street Lighting	41,049

442-Industrial	Revenues
EHG Electric Heating General	30,333
GS-1 Gen Svc Fixed	724,110
GS-2 Gen Svc Low	20,650,357
GS-3 Gen Svc Medium	71,103,287
GS-4 Gen Svc Large	203,459,330
GS-TOD Gen Svc-Time of Day	206,004
OAD GS-2 Gen Svc Low	349
OAD GS-4 Gen Svc Large	3,329,479
IR Interruptible Service	97,267,018
OL Outdoor Lighting	281,318
Net Estimated Billings	(346,843)
Subtotal-Billed	**396,704,742**
Net Unbilled	(7,450,971)
Total 442-Industrial	**389,253,771**

444-Street & Highway Lighting	Revenues
GS-1 Gen Svc Fixed	722,157
GS-2 Gen Svc Low	297,889
OAD GS-1 Gen Svc Fixed	1,570,458
OAD GS-2 Gen Svc Low	838,120
Subtotal-Billed	**3,428,624**
Net Unbilled	(19,888)
Total 444-Street & Highway Lighting	**3,408,736**

445-Pub Authorities - Other

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

FOOTNOTE DATA

Revenues

TL Traffic Light 94 FP Flood Pumping ________
14,939
TV Television Cable 225,228 **Subtotal-Billed**
14,939
OAD GS-2 Gen Svc Low 221 Net Unbilled _________
(1,234)
Net Estimated Billings (316,464) **Total 445-Pub Authorities - Other** **13,705**
Subtotal-Billed **268,068,757**
Net Unbilled (7,903,440) **Total Billed**
1,136,702,098
Total 442-Commercial **260,165,317** **Total Unbilled**
(20,792,341)

Total

1,115,909,757

Name of Respondent Ohio 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

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.
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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.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (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	Ohio Edison - 217	RQ	OPCO-99			
2	Ohio Edison - 244	RQ	OPCO-99			
3	Wheeling Power	RQ	OPCO-18			
4	AEP Service Corporation	OS	20			
5	AEP Service Corporation	OS	23			
6	Advan Promotions Inc.	OS	Note 1			
7	Allegheny Electric Cooperative	OS	Note 1			
8	ALLETE, Inc. dba Minnesota Pwr	OS	Note 1			
9	Ameren Energy Marketing	OS	Note 1			
10	AmerenCILCO, CIPS, Ameren IP	OS	Note 1			
11	American Municipal Power-Ohio	OS	Note 1			
12	American PwerNet Management	OS	Note 1			
13	Associated Elect Cooperative	OS	Note 1			
14	B.P. Energy Company	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Ohio 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

SALES FOR RESALE (Account 447)

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Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	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	Barclays Bank PLC	OS	Note 1			
2	Beech Ridge Energy LLC	OS	Note 1			
3	BP AMOCO	OS	Note 1			
4	Buckeye Rural Electric Admin	OS	Note 1			
5	California Power Exchange	OS	Note 1			
6	Calpine Power Service Company	OS	Note 1			
7	Carolina Power & Light	OS	Note 1			
8	Citigroup Energy, Inc.	OS	Note 1			
9	Citizens Elect Co & Wellsborough	OS	Note 1			
10	City of Batavia	OS	Note 1			
11	City of Columbus	OS	Note 1			
12	City of Croswell, MI	OS	Note 1			
13	City of Dowagiac, MI	OS	Note 1			
14	City of Kirkwood, Missouri	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Ohio 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

SALES FOR RESALE (Account 447)

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (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 Medford	OS	Note 1			
2	City of Shelby	OS	Note 1			
3	City of Westerville	OS	Note 1			
4	Cleveland Public Power	OS	Note 1			
5	Cleveland Toledo OH PA Electric	OS	Note 1			
6	Commonwealth Edison Company	OS	Note 1			
7	Conoco, Inc.	OS	Note 1			
8	Constellation Engy Commodities	OS	Note 1			
9	Cook Inlet Energy Supply LP	OS	Note 1			
10	Dairyland Power Cooperative	OS	Note 1			
11	DB Energy Trading LLC	OS	Note 1			
12	Delaware Electric Municipal Co.	OS	Note 1			
13	Dominion Equipment Inc.	OS	Note 1			
14	DP&L Power Services	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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

SALES FOR RESALE (Account 447)

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

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).
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					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	GBC Metals, LLC	OS	Note 1			
2	Great River Energy	OS	Note 1			
3	Harrison Rural Electrification	OS	Note 1			
4	Hoosier Power Market	OS	Note 1			
5	Illinois Municipal Elec Agency	OS	Note 1			
6	Indiana Municipal Power Agency	OS	Note 1			
7	Indianapolis Power & Light	OS	Note 1			
8	Integrys Energy Serices, Inc.	OS	Note 1			
9	Interstate Gas Supply, Inc.	OS	Note 1			
10	Interstate Power & Light Co.	OS	Note 1			
11	J ARON & Company	OS	Note 1			
12	JP Morgan Ventures Energy Corp.	OS	Note 1			
13	Kansas City Power & Light Co.	OS	Note 1			
14	Kentucky Municipal Power Agncy	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447)

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	(a)	(b)	(c)	(d)	(e)	(f)
1	L&P Electric, Inc.	OS	Note 1			
2	Letterkenny Industril Dev Auth	OS	Note 1			
3	LG&E Utilities Power Sales	OS	Note 1			
4	Michigan Public Power Agency	OS	Note 1			
5	MidAmerican Energy	OS	Note 1			
6	Midwest ISO	OS	Note 1			
7	Mizuho Securities USA Inc.	OS	Note 1			
8	Mogran Stanley Capt.	OS	Note 1			
9	NC Electric Membership Corp.	OS	Note 1			
10	NextEra Energy Power Mktg LLC	OS	Note 1			
11	No Carolina Muni Pwr Agency #1	OS	Note 1			
12	Noble Americas Gas and Power Corp.	OS	Note 1			
13	NRG Power Marketing, Inc	OS	Note 1			
14	NSP Energy Marketing	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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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 Elec.	OS	Note 1			
2	Otter Tail Power Company	OS	Note 1			
3	OVEC Power Scheduling	OS	Note 1			
4	Paribas	OS	Note 1			
5	Peco Energy Company	OS	Note 1			
6	PEPCO Services, Inc.	OS	Note 1			
7	PJM Environmental Info Sys Inc.	OS	Note 1			
8	PJM Interconnection	OS	Note 1			
9	Potomas Electrc Power Company	OS	Note 1			
10	PP&L Energy Plus Co.	OS	Note 1			
11	PPL Electric Utilities Corp.	OS	Note 1			
12	Prairie Power, Inc.	OS	Note 1			
13	Prairieland Energy Incorporate	OS	Note 1			
14	PSEG Energy Resources & Trade	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Ohio 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

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 Classifi-cation	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	Quasar Energy Power Marketing	OS	Note 1			
2	Sempra Energy Solutions, LLC	OS	Note 1			
3	Shell Energy N America (US) LP	OS	Note 1			
4	Southern Maryland Elec Coop Inc.	OS	Note 1			
5	Southern Company	OS	Note 1			
6	Southern Illinois Power Co-Op	OS	Note 1			
7	Tenaska Power Services Company	OS	Note 1			
8	The Borough of Pitcairn, PA	OS	Note 1			
9	The Energy Authority	OS	Note 1			
10	The Potomac Edison Company	OS	Note 1			
11	Timber Canyon	OS	Note 1			
12	Town of Berlin, Maryland	OS	Note 1			
13	Town of Hagerstown, Indiana	OS	Note 1			
14	TVA Bulk Power Trading	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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 Classifi-cation	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	UBS AG, London Branch	OS	Note 1			
2	UBS Securities LLC	OS	Note 1			
3	Union Electric Company	OS	Note 1			
4	Union Power Partners	OS	Note 1			
5	Village of Bethel Ohio	OS	Note 1			
6	Village of Glouster	OS	Note 1			
7	Village of Hamersville, Ohio	OS	Note 1			
8	Village of Ripley, Ohio	OS	Note 1			
9	Village of Sebewaing, MI	OS	Note 1			
10	Virginia City Hybrid Energy Center	OS	Note 1			
11	Wabash Valley Power Assn Inc.	OS	Note 1			
12	Washington Gas Energy Services	OS	Note 1			
13	West Penn Power Company	OS	Note 1			
14	Westar Energy Inc.	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Ohio 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

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 Classifi-cation (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	Wisconsin Power & Light	OS	Note 1			
2	Wolverine Power Supply Coop	OS	Note 1			
3	ADJUSTMENT	OS	Note 1			
4						
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,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.
7,458	405,302	248,133		653,435	1
500	35,326	16,728		52,054	2
2,588,175	48,042,888	87,370,519	729,228	136,142,635	3
		-70,159		-70,159	4
15,227,113	207,179,550	436,760,230		643,939,780	5
		-15,384		-15,384	6
211,247		11,496,220		11,496,220	7
-12,810		-313,760		-313,760	8
-60,153		-2,471,476		-2,471,476	9
7,182		297,582		297,582	10
153,526	1,900,597	9,042,701		10,943,298	11
34,294		1,429,866		1,429,866	12
-3,580		-95,726		-95,726	13
34,813		1,938,897		1,938,897	14
2,596,133	48,483,516	87,635,380	729,228	136,848,124	
30,029,692	245,170,997	956,347,702	98,625,702	1,300,144,401	
32,625,825	**293,654,513**	**1,043,983,082**	**99,354,930**	**1,436,992,525**	

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

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.
118,862		4,707,756		4,707,756	1
		-106,303		-106,303	2
		285,728		285,728	3
3,485,407	24,697,334	136,153,633		160,850,967	4
		1,911		1,911	5
-2,104		-49,196		-49,196	6
453		14,997		14,997	7
		114,172		114,172	8
4,371		230,342		230,342	9
11,269		423,143		423,143	10
376,782		24,961,483		24,961,483	11
17,812		863,579		863,579	12
		2,111		2,111	13
	214			214	14
2,596,133	48,483,516	87,635,380	729,228	136,848,124	
30,029,692	245,170,997	956,347,702	98,625,702	1,300,144,401	
32,625,825	**293,654,513**	**1,043,983,082**	**99,354,930**	**1,436,992,525**	

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.
55,011		3,191,008		3,191,008	1
15,439		1,102,174		1,102,174	2
119,880		10,047,967		10,047,967	3
85,486		4,462,432		4,462,432	4
	692,715	-873		691,842	5
160,812		6,829,114		6,829,114	6
		397,543		397,543	7
-3,829		-1,474,680		-1,474,680	8
		233,762		233,762	9
-1,886		110,373		110,373	10
209,125		7,760,222		7,760,222	11
78,913		5,129,334		5,129,334	12
14,348		568,189		568,189	13
		-502,114		-502,114	14
2,596,133	48,483,516	87,635,380	729,228	136,848,124	
30,029,692	245,170,997	956,347,702	98,625,702	1,300,144,401	
32,625,825	**293,654,513**	**1,043,983,082**	**99,354,930**	**1,436,992,525**	

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

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.
	9,867	-22,801		-12,934	1
128		-2,720		-2,720	2
		810,157		810,157	3
156,517		7,793,199		7,793,199	4
189,388		7,272,650		7,272,650	5
22,727		1,233,255		1,233,255	6
308,270		15,280,761		15,280,761	7
	294,546	51,501		346,047	8
		-5,148		-5,148	9
		1,728,575		1,728,575	10
		2,307,814		2,307,814	11
-1,303		-57,090		-57,090	12
-22,016		-21,485,130		-21,485,130	13
975,025		56,027,065		56,027,065	14
2,596,133	48,483,516	87,635,380	729,228	136,848,124	
30,029,692	245,170,997	956,347,702	98,625,702	1,300,144,401	
32,625,825	**293,654,513**	**1,043,983,082**	**99,354,930**	**1,436,992,525**	

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.
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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.
		42,802		42,802	1
		-72,316		-72,316	2
41,026		3,292,764		3,292,764	3
9,438		248,013		248,013	4
208		14,811		14,811	5
	10,371	93,608		103,979	6
	20,816			20,816	7
		353,265		353,265	8
		-5,426		-5,426	9
32,550		724,226		724,226	10
1,213,129		34,894,522		34,894,522	11
221,161		-2,824,316		-2,824,316	12
-285		-6,886		-6,886	13
29,613		1,716,752		1,716,752	14
2,596,133	48,483,516	87,635,380	729,228	136,848,124	
30,029,692	245,170,997	956,347,702	98,625,702	1,300,144,401	
32,625,825	**293,654,513**	**1,043,983,082**	**99,354,930**	**1,436,992,525**	

SALES FOR RESALE (Account 447) (Continued)

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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.
13,699		491,572		491,572	1
32,613		2,181,325		2,181,325	2
193		5,987		5,987	3
54,057		3,287,338		3,287,338	4
		-1,516,745		-1,516,745	5
-1,228,310		-38,396,095		-38,396,095	6
		4,713,705		4,713,705	7
12,371		-532,846		-532,846	8
939,521		35,449,609		35,449,609	9
4,299		1,572,613		1,572,613	10
70		2,113		2,113	11
		122,429		122,429	12
-55,598		-1,534,191		-1,534,191	13
		378,758		378,758	14
2,596,133	48,483,516	87,635,380	729,228	136,848,124	
30,029,692	245,170,997	956,347,702	98,625,702	1,300,144,401	
32,625,825	**293,654,513**	**1,043,983,082**	**99,354,930**	**1,436,992,525**	

Name of Respondent Ohio 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

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.
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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)
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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.
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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.
141,049		6,892,919		6,892,919	1
		11,290		11,290	2
44,419		1,574,831		1,574,831	3
		9,847		9,847	4
13,904		1,010,434		1,010,434	5
23,675		1,248,796		1,248,796	6
		-295		-295	7
5,039,290	10,360,480	127,193,097	98,625,702	236,179,279	8
127,885		9,809,009		9,809,009	9
		-3,721,617		-3,721,617	10
29,284		2,036,170		2,036,170	11
42,093		2,777,739		2,777,739	12
79,412	-74	2,570,276		2,570,202	13
62,855		1,888,096		1,888,096	14
2,596,133	48,483,516	87,635,380	729,228	136,848,124	
30,029,692	245,170,997	956,347,702	98,625,702	1,300,144,401	
32,625,825	**293,654,513**	**1,043,983,082**	**99,354,930**	**1,436,992,525**	

SALES FOR RESALE (Account 447) (Continued)

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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.
-1,370		-36,189		-36,189	1
		3,308,322		3,308,322	2
68		3,434		3,434	3
2,238		126,466		126,466	4
7,257		214,580		214,580	5
7,158		236,725		236,725	6
-171		-3,554		-3,554	7
5,579		239,305		239,305	8
6,713		245,054		245,054	9
666		39,116		39,116	10
		-15,384		-15,384	11
18,192		1,150,993		1,150,993	12
10,361		632,521		632,521	13
647		42,257		42,257	14
2,596,133	48,483,516	87,635,380	729,228	136,848,124	
30,029,692	245,170,997	956,347,702	98,625,702	1,300,144,401	
32,625,825	**293,654,513**	**1,043,983,082**	**99,354,930**	**1,436,992,525**	

SALES FOR RESALE (Account 447) (Continued)

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MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
		-318,380		-318,380	1
		-24,431,461		-24,431,461	2
		-934,120		-934,120	3
-3,266		-68,113		-68,113	4
12,048		624,958		624,958	5
718		145,676		145,676	6
2,231		123,500		123,500	7
8,212		423,098		423,098	8
19,543		935,832		935,832	9
		465,107		465,107	10
		343,931		343,931	11
458,981		22,592,324		22,592,324	12
-169		-9,004		-9,004	13
42,302		784,442		784,442	14
2,596,133	48,483,516	87,635,380	729,228	136,848,124	
30,029,692	245,170,997	956,347,702	98,625,702	1,300,144,401	
32,625,825	**293,654,513**	**1,043,983,082**	**99,354,930**	**1,436,992,525**	

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30,428		1,105,168		1,105,168	1
511,186	4,581	17,827,221		17,831,802	2
		-1,832,992		-1,832,992	3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
2,596,133	48,483,516	87,635,380	729,228	136,848,124	
30,029,692	245,170,997	956,347,702	98,625,702	1,300,144,401	
32,625,825	**293,654,513**	**1,043,983,082**	**99,354,930**	**1,436,992,525**	

Schedule Page: 310 Line No.: 3 Column: a

AEP Affiliate.

Schedule Page: 310 Line No.: 3 Column: j

Amount represents transmission service and related charges.

Schedule Page: 310 Line No.: 4 Column: a

Affiliated Company - transactions related to the System Integration Agreement. See pages 122-123 (Notes to Financial Statements) Related Party Transactions - System Integraton Agreement for additional information.

Schedule Page: 310 Line No.: 5 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 Line No.: 6 Column: c

NOTE 1: FERC Electric Tariff, First Revised Volumn No. 5.

Schedule Page: 310.6 Line No.: 8 Column: j

Amount represents capacity revenues from Competitive Retail Electric Service (CRES) providers.

Schedule Page: 310.9 Line No.: 3 Column: a

Reclass between 447 and 555 accounts to incorporate certain trading/marketing activity. The amounts represented on Page 310-311 and 326-327 are equal and off-setting.

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	21,095,125	24,252,372
5	(501) Fuel	1,342,546,762	1,420,996,722
6	(502) Steam Expenses	119,662,156	143,753,090
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	2,963,159	3,386,294
10	(506) Miscellaneous Steam Power Expenses	64,288,991	167,633,071
11	(507) Rents	13,606	33,333
12	(509) Allowances	14,413,222	48,784,433
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	1,564,983,021	1,808,839,315
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	16,902,347	14,894,516
16	(511) Maintenance of Structures	10,765,085	13,663,576
17	(512) Maintenance of Boiler Plant	119,000,715	195,397,381
18	(513) Maintenance of Electric Plant	26,375,615	35,698,220
19	(514) Maintenance of Miscellaneous Steam Plant	13,156,766	14,561,150
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	186,200,528	274,214,843
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	1,751,183,549	2,083,054,158
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	69,431	29,969
45	(536) Water for Power	29,229	25,443
46	(537) Hydraulic Expenses	1,347	3,885
47	(538) Electric Expenses		889
48	(539) Miscellaneous Hydraulic Power Generation Expenses	192,234	171,033
49	(540) Rents	41,666	50,000
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	333,907	281,219
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	952	4,918
54	(542) Maintenance of Structures	123,198	20,668
55	(543) Maintenance of Reservoirs, Dams, and Waterways	28,520	11,606
56	(544) Maintenance of Electric Plant	326,918	535,393
57	(545) Maintenance of Miscellaneous Hydraulic Plant	59,652	250,998
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	539,240	823,583
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	873,147	1,104,802

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	172,178	169,004
63	(547) Fuel	3,586,443	2,940,639
64	(548) Generation Expenses	161,022	214,004
65	(549) Miscellaneous Other Power Generation Expenses	332,805	304,382
66	(550) Rents	34,963	51,442
67	TOTAL Operation (Enter Total of lines 62 thru 66)	4,287,411	3,679,471
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	71,720	73,647
70	(552) Maintenance of Structures	14,638	11,734
71	(553) Maintenance of Generating and Electric Plant	633,617	982,596
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	123,871	128,811
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	843,846	1,196,788
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	5,131,257	4,876,259
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	642,150,858	892,250,028
77	(556) System Control and Load Dispatching	2,410,516	2,904,180
78	(557) Other Expenses	23,375,679	20,171,331
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	667,937,053	915,325,539
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	2,425,125,006	3,004,360,758
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	5,005,275	4,278,466
84			
85	(561.1) Load Dispatch-Reliability	34,962	36,600
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	5,013,509	4,932,726
87	(561.3) Load Dispatch-Transmission Service and Scheduling	-480	35
88	(561.4) Scheduling, System Control and Dispatch Services	8,170,124	7,287,434
89	(561.5) Reliability, Planning and Standards Development	798,616	723,997
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	1,734,018	1,677,972
93	(562) Station Expenses	1,440,420	1,530,359
94	(563) Overhead Lines Expenses	180,095	447,896
95	(564) Underground Lines Expenses	489	230
96	(565) Transmission of Electricity by Others	22,667,784	33,282,508
97	(566) Miscellaneous Transmission Expenses	-13,848,194	-23,555,771
98	(567) Rents	259,015	281,096
99	TOTAL Operation (Enter Total of lines 83 thru 98)	31,455,633	30,923,548
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	278,172	299,190
102	(569) Maintenance of Structures	150,852	199,131
103	(569.1) Maintenance of Computer Hardware	214,439	271,987
104	(569.2) Maintenance of Computer Software	1,100,968	1,287,033
105	(569.3) Maintenance of Communication Equipment	398,959	828,092
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	5,365,972	6,675,061
108	(571) Maintenance of Overhead Lines	12,591,310	8,682,174
109	(572) Maintenance of Underground Lines	330,496	394,118
110	(573) Maintenance of Miscellaneous Transmission Plant	952,585	494
111	TOTAL Maintenance (Total of lines 101 thru 110)	21,383,753	18,637,280
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	52,839,386	49,560,828

Name of Respondent Ohio 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

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services	8,466,532	7,630,463
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	8,466,532	7,630,463
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)	8,466,532	7,630,463
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	6,450,153	5,352,042
135	(581) Load Dispatching	16,374	12,251
136	(582) Station Expenses	1,963,394	2,151,550
137	(583) Overhead Line Expenses	681,367	2,097,553
138	(584) Underground Line Expenses	1,447,991	3,281,619
139	(585) Street Lighting and Signal System Expenses	181,753	203,799
140	(586) Meter Expenses	2,141,871	2,783,267
141	(587) Customer Installations Expenses	120,422	362,021
142	(588) Miscellaneous Expenses	34,940,338	27,907,214
143	(589) Rents	5,021,728	6,366,649
144	TOTAL Operation (Enter Total of lines 134 thru 143)	52,965,391	50,517,965
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	666,635	687,274
147	(591) Maintenance of Structures	410,644	479,449
148	(592) Maintenance of Station Equipment	5,004,560	5,826,242
149	(593) Maintenance of Overhead Lines	87,464,618	75,964,519
150	(594) Maintenance of Underground Lines	4,875,786	3,839,105
151	(595) Maintenance of Line Transformers	1,245,315	1,137,785
152	(596) Maintenance of Street Lighting and Signal Systems	414,846	341,454
153	(597) Maintenance of Meters	516,626	568,320
154	(598) Maintenance of Miscellaneous Distribution Plant	2,000,287	2,383,191
155	TOTAL Maintenance (Total of lines 146 thru 154)	102,599,317	91,227,339
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	155,564,708	141,745,304
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	1,612,514	2,220,151
160	(902) Meter Reading Expenses	7,836,431	7,519,338
161	(903) Customer Records and Collection Expenses	44,845,230	46,627,577
162	(904) Uncollectible Accounts	87,397,194	83,563,951
163	(905) Miscellaneous Customer Accounts Expenses	6,113,008	267,744
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	147,804,377	140,198,761

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	4,180,177	6,783,352
168	(908) Customer Assistance Expenses	85,852,106	89,082,204
169	(909) Informational and Instructional Expenses	1,383	47,388
170	(910) Miscellaneous Customer Service and Informational Expenses	26,087	75,490
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	90,059,753	95,988,434
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision	1,490,392	524,434
175	(912) Demonstrating and Selling Expenses	21	1,184
176	(913) Advertising Expenses	88,618	
177	(916) Miscellaneous Sales Expenses	24,418	26,170
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	1,603,449	551,788
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	42,516,721	42,022,460
182	(921) Office Supplies and Expenses	3,439,653	5,292,614
183	(Less) (922) Administrative Expenses Transferred-Credit	8,643,861	7,184,485
184	(923) Outside Services Employed	34,020,334	38,432,096
185	(924) Property Insurance	6,727,215	8,402,053
186	(925) Injuries and Damages	10,295,892	13,989,856
187	(926) Employee Pensions and Benefits	43,128,555	41,913,468
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	1,726,872	1,332,005
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	14,095,546	6,458,420
192	(930.2) Miscellaneous General Expenses	1,114,296	2,177,555
193	(931) Rents	2,996,811	3,236,075
194	TOTAL Operation (Enter Total of lines 181 thru 193)	151,418,034	156,072,117
195	Maintenance		
196	(935) Maintenance of General Plant	7,757,754	7,843,633
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	159,175,788	163,915,750
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	3,040,638,999	3,603,952,086

Schedule Page: 320 Line No.: 103 Column: 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.

Name of Respondent Ohio 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

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	RQ	AEG 3			
2	AEP Service Corporation	OS	23			
3	AEP Service Corporation	OS	20			
4	Ameren Energy Marketing	OS				
5	American Municipal Power-Ohio	OS				
6	Associated Elect Cooperative	OS				
7	B.P. Energy Company	OS				
8	Barclays Bank PLC	OS				
9	Beech Ridge Energy LLC	OS				
10	BP AMOCO	OS				
11	Buckeye Rural Electric Admin	OS				
12	Constellation Engy Commodities	OS				
13	DP&L Power Services	OS				
14	Duke Energy Carolinas, LLC	OS				
	Total					

Name of Respondent Ohio 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

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.
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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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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	Dynegy Power Marketing Inc.	OS				
2	East KY Power Co-Op Power Mktg	OS				
3	EDF Trading North America LLC	OS				
4	Energy America, LLC	OS				
5	Entergy Power Serv	OS				
6	Exelon Generation - Power Team	OS				
7	Fowler Ridge II Wind Farm LLC	OS				
8	J ARON & Company	OS				
9	JP Morgan Ventures Energy Corp	OS				
10	LG&E Utilities Power Sales	OS				
11	Midwest ISO	OS				
12	Mingo Junction Energy Center	OS				
13	Mizuho Securities USA Inc.	OS				
14	National Power Cooperative Inc.	OS				
	Total					

Name of Respondent Ohio 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

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.
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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	National Power Cooperative Inc.	OS				
2	NC Electric Membership Corp.	OS				
3	NextEra Energy Power Mktg LLC	OS				
4	No Carolina Muni Pwr Agency #1	OS				
5	NRG Power Marketing Inc.	OS				
6	Ohio DSM Interuptible Credit	OS				
7	Ohio Economic Development Rider	OS				
8	Ohio ESP Capacity Cost	OS				
9	Old Dominion Elec.	OS				
10	OVEC Power Scheduling	OS				
11	Paulding Wind Farm	OS				
12	PJM Environmental Info Sys Inc.	OS				
13	PJM Interconnection	OS				
14	R L Downs	OS				
	Total					

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

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.

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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	Southern Maryland Elec Coop Inc.	OS				
2	Southern Company	OS				
3	The Energy Authority	OS				
4	TVA Bulk Power Trading	OS				
5	UBS Securities LLC	OS				
6	Wabash Valley Power Assn Inc.	OS				
7	Wisconsin Electric Power Co.	OS				
8	Wisconsin Power & Light	OS				
9	WPPI Energy	OS				
10	Wyandot Solar LLC	OS				
11	ADJUSTMENT	OS				
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		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)	
6,634,276			62,395,756	141,186,702		203,582,458	1
5,283,737				174,240,043		174,240,043	2
2,796				75,510		75,510	3
			11,319			11,319	4
17,661				780,303		780,303	5
2,634				75,004		75,004	6
				-40,001		-40,001	7
				467,461		467,461	8
				-73,160		-73,160	9
				-63,964		-63,964	10
				1,045,248		1,045,248	11
115,625			2,109,442	3,415,956		5,525,398	12
				70,100		70,100	13
33				2,455		2,455	14
17,646,286			134,068,214	517,165,557	-9,082,913	642,150,858	

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)	
			19,613			19,613	1
349				9,079		9,079	2
			40,411			40,411	3
				166,645		166,645	4
1,884				44,982		44,982	5
				2,926,381		2,926,381	6
277,843				17,850,091		17,850,091	7
				-74,399		-74,399	8
			133,625			133,625	9
3,734				163,556		163,556	10
12,199			2	342,926		342,928	11
29,534				524,080		524,080	12
				630,422		630,422	13
			148,645	2,458,239		2,606,884	14
17,646,286			134,068,214	517,165,557	-9,082,913	642,150,858	

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.
35,983							1
230				8,832		8,832	2
				342,087		342,087	3
6				179		179	4
299				10,781		10,781	5
				-7,454,799		-7,454,799	6
					4,689,818	4,689,818	7
					-13,772,731	-13,772,731	8
581				19,455		19,455	9
1,952,388			65,397,391	59,488,326		124,885,717	10
				7,540		7,540	11
				373		373	12
2,982,565			3,780,633	109,962,753		113,743,386	13
				138		138	14
17,646,286			134,068,214	517,165,557	-9,082,913	642,150,858	

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)	
478				15,723		15,723	1
42				2,329		2,329	2
36,326				1,547,130		1,547,130	3
239,315				5,420,021		5,420,021	4
				2,049,210		2,049,210	5
			5			5	6
			4,207			4,207	7
			17,656			17,656	8
			9,509			9,509	9
15,768				1,354,812		1,354,812	10
				-1,832,992		-1,832,992	11
							12
							13
							14
17,646,286			134,068,214	517,165,557	-9,082,913	642,150,858	

Schedule Page: 326 Line No.: 1 Column: a

AEP Affiliate.

Schedule Page: 326.2 Line No.: 7 Column: l

The PUCO authorized OPCO to defer any under recovery of purchased power expense equal to the difference between the ESP tariff rate and the rate paid by certain customers under the Economic Development Rider (EDR). Charges/Credits to the (EDR) regulatory asset are offset to account 5550110.

Schedule Page: 326.2 Line No.: 8 Column: l

The PUCO authorized OPCO to defer the difference between Electric Security Plan (ESP) Capacity Cost incurred up to $188/MW-day and RPM pricing as approved by the PUCO in Case No. 10-2929-EL-UNC. A portion of the charges to the (ESP) regulatory asset are offset to account 5550117.

Schedule Page: 326.3 Line No.: 11 Column: a

Reclass between 447 and 555 accounts to incorporate certain trading/marketing activity. The amounts represented on Page 310-311 and 326-327 are equal and off-setting.

Name of Respondent Ohio 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

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 Classification (d)
1	PJM Network Integ Trans Rev	Various	Various	FNO
2	PJM Network Integ Trans Serv	Various	Various	FNO
3	PJM Trans Enhancement Rev	Various	Various	FNO
4	PJM Trans Enhancement Rev Whlsle	Various	Various	FNO
5	PJM Network Integ Rev - Affil	Various	Various	FNS
6	PJM Trans Enhancement Rev - Affil	Various	Various	FNS
7	PJM Point to Point Trans Service	Various	Various	LFP
8	PJM Trans Owner Admin Revenue	Various	Various	OLF
9	PJM Trans Owner Serv - Affiliated	Various	Various	OLF
10	PJM Trans Owner Serv Rev Whlsle	Various	Various	OLF
11	PJM Expansion Costs Recovery	Various	Various	OS
12	PJM Trans Distribution & Metering	Various	Various	OS
13	RTO Formation Cost Recovery	Various	Various	OS
14	SECA Transmission Rev	Various	Various	OS
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

Name of Respondent Ohio 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

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		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
PJM OATT	Various	Various				1
PJM OATT	Various	Various				2
PJM OATT	Various	Various				3
PJM OATT	Various	Various				4
PJM OATT	Various	Various				5
PJM OATT	Various	Various				6
PJM OATT	Various	Various				7
PJM OATT	Various	Various				8
PJM OATT	Various	Various				9
PJM OATT	Various	Various				10
PJM OATT	Various	Various				11
PJM OATT	Various	Various				12
PJM OATT	Various	Various				13
PJM OATT	Various	Various				14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						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.
12,606,431			12,606,431	1
51,420,648			51,420,648	2
817,927			817,927	3
83,734			83,734	4
25,252,050			25,252,050	5
156,459			156,459	6
3,521,291			3,521,291	7
	1,546,235		1,546,235	8
	886,094		886,094	9
	238,919		238,919	10
687,476			687,476	11
		1,355,970	1,355,970	12
364,687			364,687	13
		1,255,682	1,255,682	14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
94,910,703	**2,671,248**	**2,611,652**	**100,193,603**	

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.

Schedule Page: 328 Line No.: 12 Column: m

Per Proforma ILDSA (Interconnection and Local Delivery Service Agreement) AEP Tariff 3rd Revised Volume No. 6.

Schedule Page: 328 Line No.: 14 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 (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio 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	Wheeling Power	LFP					1,351,836	1,351,836
2	PJM-Ehancements	OS					15,371,655	15,371,655
3	PJM-NITS	OS					5,943,866	5,943,866
4	Other	OS					427	427
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL						22,667,784	22,667,784

Schedule Page: 332 Line No.: 1 Column: a

Affiliated Company.

Schedule Page: 332 Line No.: 1 Column: g

Amount represents charges for leased lines.

Schedule Page: 332 Line No.: 2 Column: a

Transmission Enhancement Charges and Credits (PJM OATT Schedule 12).

Schedule Page: 332 Line No.: 3 Column: a

Network Integration Service Charges-NITS (PJM OATT Schedule H).

Schedule Page: 332 Line No.: 4 Column: a

Midwest Independent Transmission System Operator (MISO) Membership/Participant Dues.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio 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	502,158
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	16,094
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	46,116
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Affiliated Billings (net)	-294,301
7	Associated Business Development	1,091,815
8	Utility Corp Borrowing Program Shared Costs	66,905
9	Corporate Contributions & Memberships	822,724
10	Gridsmart Initiative	-1,117,233
11	Chamber of Commerce	23,991
12	Clearing of Unclaimed Funds (business to business)	-48,350
13	Various Items <$5,000	4,377
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46	TOTAL	1,114,296

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio 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			23,926,774		23,926,774
2	Steam Production Plant	304,974,095	12,053,443			317,027,538
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	3,038,210	2,174			3,040,384
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	9,223,915				9,223,915
7	Transmission Plant	44,851,117				44,851,117
8	Distribution Plant	94,896,667				94,896,667
9	Regional Transmission and Market Operation					
10	General Plant	2,600,803		274,113		2,874,916
11	Common Plant-Electric					
12	TOTAL	459,584,807	12,055,617	24,200,887		495,841,311

B. Basis for Amortization Charges

Line 1, Column D $23,925,113 represents amortization of capitalized software development costs over a 5 year life and $1,661 represents amortization of franchise over the life of the franchise.

Line 10, Column D represents amortization of leasehold improvements to equipment and structures over the life of the lease.

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 GENERATION						
13	311 - Amos	43,518			2.29		
14	311 - Cardinal	43,712			2.38		
15	311 - Conesville	55,594			1.79		
16	311 - Conesville Scrubb	3,766			1.79		
17	311 - Gavin	109,966			2.44		
18	311 - Gavin JMG	1,200			2.44		
19	311 - Gypsum Unloader	22			2.38		
20	311 - Kammer	35,237					
21	311 - Mitchell	82,600			2.87		
22	311 - Muskingum U1-4	28,878					
23	311 - Muskingum U5	23,635			2.80		
24	311.1 - MR U5 Coal Hndl	6,245					
25	311 - Picway	6,668					
26	311 - Putnam	853			2.29		
27	311 - Sporn	10,981					
28	311.15 - Beckjord	1,351					
29	311.15 - Conesville U4	17,653			1.58		
30	311.15 - Stuart	25,698			1.75		
31	311.15 - Zimmer	169,711			1.41		
32	312 - Amos	834,055			2.88		
33	312 - Cardinal	590,412			3.16		
34	312 - Cardinal SCR	5,556			10.00		
35	312 - Conesville	378,703			1.90		
36	312 - Conesville Scrubb	93,040			1.90		
37	312 - Gavin	802,076			2.96		
38	312 - Gavin JMG	713,766			2.96		
39	312 - Gavin SCR	26,740			10.00		
40	312 - Gypsum Unloader	13,203			3.12		
41	312 - Kammer	229,101					
42	312 - Mitchell	1,492,352			3.90		
43	312 - Mitchell SCR	13,254			10.00		
44	312 - Muskingum U1-4	197,251					
45	312 - Muskingum U5	221,687			3.43		
46	312 - Muskingum U5 SCR	4,112			10.00		
47	312.1 - MR U5 Coal Hndl	47,234					
48	312 - Picway	24,151					
49	312 - Putnam	1,544			2.88		
50	312 - Simulator	125			2.88		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio 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	312 - Sporn	101,442					
13	312.15 - Beckjord	11,735					
14	312.15 - Conesville U4	253,948			1.66		
15	312.15 - Stuart	439,827			2.41		
16	312.15 - Zimmer	399,803			1.57		
17	314 - Amos	69,567			2.78		
18	314 - Cardinal	50,594			2.99		
19	314 - Conesville	102,247			2.02		
20	314 - Gavin	190,291			2.91		
21	314 - Kammer	47,847					
22	314 - Mitchell	105,849			2.86		
23	314 - Muskingum U1-4	57,953					
24	314 - Muskingum U5	47,723			3.19		
25	314 - Picway	6,277					
26	314 - Sporn	28,843					
27	314.15 - Beckjord	3,710					
28	314.15 - Conesville U4	30,612			1.84		
29	314.15 - Stuart	57,488			2.29		
30	314.15 - Zimmer	122,736			1.52		
31	315 - Amos	16,273			2.32		
32	315 - Cardinal	21,677			2.66		
33	315 - Conesville	35,714			1.57		
34	315 - Conesville Scrubb	2,273			1.57		
35	315 - Gavin	59,510			2.28		
36	315 - Kammer	18,239					
37	315 - Mitchell	30,048			2.39		
38	315 - Muskingum U1-4	19,097					
39	315 - Muskingum U5	9,472			2.62		
40	315 - Picway	4,009					
41	315 - Putnam	146			2.32		
42	315 - Simulator	870			2.32		
43	315 - Sporn	7,982					
44	315.15 - Beckjord	762					
45	315.15 - Conesville U4	4,503			1.71		
46	315.15 - Stuart	10,670			1.90		
47	315.15 - Zimmer	92,191			1.44		
48	316 - Amos	7,767			2.62		
49	316 - Cardinal	6,715			2.98		
50	316 - Conesville	15,690			1.85		

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	316 - Conesville Scrubb	55			1.85		
13	316 - Gavin	21,682			2.73		
14	316 - Kammer	6,535					
15	316 - Mitchell	14,240			2.79		
16	316 - Muskingum U1-4	9,723					
17	316 - Muskingum U5	3,907			2.94		
18	316.1- MR U5 Coal Hndl	390					
19	316 - Picway	2,811					
20	316 - Putnam	150			2.62		
21	316 - Simulator	2,348			2.62		
22	316 - Sporn	3,485					
23	316.15 - Beckjord	1,212					
24	316.15 - Conesville U4	1,091			1.80		
25	316.15 - Stuart	5,385			2.39		
26	316.15 - Zimmer	16,489			1.51		
27	TOTAL STEAM	8,937,253					
28							
29	HYDRO GENERATION						
30	331	49,979			2.78		
31	332	6,304			2.60		
32	333	43,865			2.56		
33	334	10,018			2.57		
34	335	4,434			2.36		
35	TOTAL HYDRO	114,600					
36							
37	OTHER GENERATION						
38	341 - Darby	3,334			1.48		
39	341 - Waterford	14,242			2.86		
40	342 - Darby	4,579			1.50		
41	342 - Waterford	3,011			2.86		
42	344 - Darby	161,591			1.63		
43	344 - Waterford	164,592			2.86		
44	345 - Darby	17,351			1.51		
45	345 - Waterford	29,198			2.86		
46	346 - Darby	3,085			1.45		
47	346 - Waterford	5,632			2.86		
48	TOTAL OTHER	406,615					
49							
50	TRANSMISSION						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio 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	352	84,920	55.00	5.00	2.02	R3	
13	352.15	358	55.00	5.00	2.02	R3	
14	352 - Kammer	15					
15	352 - Muskingum U1-4	22					
16	352 - Picway	7					
17	352 - Sporn U2 and U4	62					
18	353	1,036,326	43.00	-30.00	2.29	R1	
19	353.15	23,713	43.00	-30.00	2.29	R1	
20	353 - Kammer	1,294					
21	353 - Muskingum U1-4	3,801					
22	353 - Picway	330					
23	353 - Sporn U2 and U4	704					
24	354	3,469	60.00		1.88	R4	
25	354.15	18,005	60.00		1.88	R4	
26	354 - All Other	151,550	60.00		1.88	R4	
27	355	136,083	39.00	-4.00	3.52	R1	
28	355.15	3,876	39.00	-4.00	3.52	R1	
29	355 - All Other	96,553	39.00	-4.00	3.52	R1	
30	356	76,353	44.00	-4.00	1.91	R4	
31	356.15	14,046	44.00	-4.00	1.91	R4	
32	356 - All Other	203,033	44.00	-4.00	1.91	R4	
33	357	396	50.00	-1.00	2.26	R2	
34	357 - All Other	10,498	50.00	-1.00	2.26	R2	
35	358	1,058	50.00	-16.00	3.27	R2	
36	358 - All Other	18,628	50.00	-16.00	3.27	R2	
37	TOTAL TRANSMISSION	1,885,100					
38							
39	DISTRIBUTION						
40	361	20,466	60.00	19.00	2.03	R1.5	
41	362	530,737	40.00	16.00	2.90	L0	
42	363	5,062	15.00		6.67	SQ	
43	364	597,024	32.00	87.00	5.34	L0	
44	365	599,271	30.00	16.00	3.30	L0	
45	366	176,022	50.00		1.79	R2	
46	367	515,500	36.00	14.00	3.39	R0.5	
47	368	659,834	34.00	15.00	3.34	R1.5	
48	369	290,501	33.00	20.00	3.54	R0.5	
49	370	158,036	36.00	17.00	3.43	S1	
50	370.16	16,800			14.29		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio 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	371	50,202	12.00	21.00	9.63	L0	
13	372	104	30.00		3.33	R1	
14	373	35,591	20.00	18.00	5.40	L0	
15	TOTAL DISTRIBUTION	3,655,150					
16							
17	GENERAL PLANT						
18	390	116,264	45.00	5.00	2.14	L1	
19	390 - Kammer	35					
20	390 - Sporn U2 and U4	4					
21	391	7,726	30.00		3.33	SQ	
22	391.15	31	30.00		3.33	SQ	
23	391 - Kammer	132					
24	391 - Muskingum U1-4	6					
25	391 - Picway	71					
26	391 - Sporn U2 and U4	122					
27	392	44	50.00		2.00	SQ	
28	392 - Picway	27					
29	393	608	34.00		2.94	SQ	
30	393 - Picway	22					
31	393 - Sporn U2 and U4	1					
32	394	32,202	30.00	9.00	3.58	SQ	
33	394 - Muskingum U1-4	9					
34	394 - Picway	11					
35	395	1,008	28.00		3.57	SQ	
36	395 - Muskingum U1-4	87					
37	396	613	26.00	-6.00	3.61	SQ	
38	396 - Muskingum U1-4	10					
39	397	55,056	35.00		2.86	SQ	
40	397.14 - Zimmer	12	35.00		2.86	SQ	
41	397.15 - Stuart	8	35.00		2.86	SQ	
42	397.16	2,175	7.00		14.29		
43	397 - Kammer	11					
44	397 - Muskingum U1-4	41					
45	397 - Picway	18					
46	397 - Sporn U2 and U4	14					
47	398	3,921	25.00		4.00	SQ	
48	398 - Picway	115					
49	TOTAL GENERAL PLANT	220,404					
50							

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	DEPRECIABLE SUM	15,219,122					
13							
14							
15							
16							
17							
18							
19							
20							
21							
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49							
50							

Schedule Page: 336 Line No.: 2 Column: b

Includes depreciation expense for capital leased assets in accordance with FASB No. 13

Schedule Page: 336 Line No.: 10 Column: b

Includes depreciation expense for capital leased assets in accordance with FASB No. 13

Schedule Page: 336 Line No.: 20 Column: b

The Kammer plant was classified as impaired as of November 30, 2012. The current plan is to operate the plant through its scheduled end of life (04/2015). AEP will continue to record a depreciable base for this plant on FERC Pg. 337; however, no additional depreciation will be recorded after Nov. 30, 2012, on this impaired asset.

Schedule Page: 336 Line No.: 22 Column: b

Muskingum Units 1-4 were classified as impaired as of November 30, 2012. The current plan is to operate these units through their scheduled end of life (04/2015). AEP will continue to record a depreciable base for these units on FERC Pg. 337; however, no additional depreciation will be recorded after Nov. 30, 2012, on this impaired asset.

Schedule Page: 336 Line No.: 25 Column: b

The Picway plant was classified as impaired as of November 30, 2012. The current plan is to operate this plant through its scheduled end of life (04/2015). AEP will continue to record a depreciable base for this plant on FERC Pg. 337; however, no additional depreciation will be recorded after Nov. 30, 2012, on this impaired asset.

Schedule Page: 336 Line No.: 27 Column: b

Sporn Units 2 and 4 were classified as impaired as of November 30, 2012. The current plan is to operate these units through their scheduled end of life (04/2015). AEP will continue to record a depreciable base for these units on FERC Pg. 337; however, no additional depreciation will be recorded after Nov. 30, 2012, on this impaired asset.

Schedule Page: 336 Line No.: 28 Column: b

Beckjord Unit 6 was classified as impaired as of November 30, 2012. The current plan is to operate this unit through its scheduled end of life (04/2015). AEP will continue to record a depreciable base for this unit on FERC Pg. 337; however, no additional depreciation will be recorded after Nov. 30, 2012, on this impaired asset.

Schedule Page: 336.5 Line No.: 12 Column: b

(1) Depreciable plant base in column B represents plant balances as of 11/30/2012

(2) Subaccounts .15 to all accounts indicate a segregation of facilities owned as tenants in common by Duke Energy, The Dayton Power and Light Company and the Respondent

(3) Depreciation for 2012 was computed monthly by application of rate to prior month ending balances

(4) In Case No. 91-418-EL-AIR for Columbus Southern Power and for Ohio Power Company, in Case No. 94-996-EL-AIR, AEP received approval to merge these two companies into one company, Ohio Power Company. For financial reporting, this merger was completed at December 31, 2011. Financial reporting for the year 2012 presented one surviving Ohio Power Company. Factors presented in Section C for the year 2012, are for the surviving Ohio Power Company.

(5) In December 2012, AEP retired Conesville Plant Unit 3 and Retrofit from its fleet

Name of Respondent Ohio 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

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	PUCO charge for funding the cost of hearing				
2	and review process for long-term forcasts.	273,842		273,842	
3					
4	Racine Hydro Project #2570				
5	Proportion of Cost of Administering the				
6	Federal Water Power Act	87,615		87,615	
7					
8	AEP Ohio Electric Security Plan				
9	PUCO Case No. 11-346-EL-SSO (OPCO)				
10	PUCO Case No. 11-348-EL-SSO (CSP)		991,905	991,905	
11					
12	Ohio East Pool Modification Filing				
13	PUCO Case No. 12-1126-EL-UNC				
14	FERC Case No. ER13-233-000 (APCo RS)				
15	FERC Case No. ER13-234-000 (KPCo RS)				
16	FERC Case No. ER13-235-000 (I&M RS)				
17	FERC Case No. ER13-236-000 (AEP Gen RS)				
18	FERC Case No. ER13-237-000 (OPCo RS)		67,004	67,004	
19					
20	AEP Ohio Distribution Case				
21	PUCO Case No. 11-351-EL-AIR (CSP)				
22	PUCO Case No. 11-352-EL-AIR (OPCO)		47,386	47,386	
23					
24	Ohio Securitization				
25	PUCO Case No. 12-1969-EL-ATS		66,646	66,646	
26					
27	Ohio Corporate Separation				
28	PUCO Case No. 12-1126-EL-UNC				
29	FERC Case No. EC13-26-000		134,718	134,718	
30					
31	Miscellaneous Items		57,756	57,756	
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	361,457	1,365,415	1,726,872	

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
Electric	928	273,842					2
							3
							4
							5
Electric	928	87,615					6
							7
							8
							9
Electric	928	991,905					10
							11
							12
							13
							14
							15
							16
							17
Electric	928	67,004					18
							19
							20
							21
Electric	928	47,386					22
							23
							24
Electric	928	66,646					25
							26
							27
							28
Electric	928	134,718					29
							30
Electric	928	57,756					31
							32
							33
							34
							35
							36
							37
							38
							39
							40
							41
							42
							43
							44
							45
		1,726,872					46

Name of Respondent Ohio 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

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) Generation	
2	(b) Fossil-fuel Steam	6 items under $50,000
3		
4	(c) Internal combustion or gas turbine	1 items under $50,000
5		
6	(e) Unconventional Generation	3 items under $50,000
7		
8	A.(2) Transmission	4 items under $50,000
9		
10	(a) Overhead	1 items under $50,000
11		
12	A.(3) Distribution	1 items under $50,000
13		
14	A.(5) Environment	Industrial Advisory Committee - Southern Co.
15		3 items under $50,000
16		
17	A.(6) Other	7 items under $50,000
18		
19	A (7) TOTAL COST INCURRED INTERNALLY	
20		
21	ELECTRIC UTILITY RESEARCH, DEVELOPMENT &	
22	DEMONSTRATION PERFORMED EXTERNALLY	
23		
24	B. (1) Electric Power Research Institute	EPRI - Full Scale Demonstration of the Sorbent Activation Process (SAP)
25		EPRI Environmental Controls
26		EPRI Environmental Science
27		EPRI Research Portfolio
28		Ohio River Ecological Research Program
29		80 items under $50,000
30		
31	B. (4) Research Support to Others	5 items under $50,000
32		
33	B(5) TOTAL COSTS INCURRED EXTERNALLY	
34		
35		
36		
37		
38		

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)		
					1
82,613		506	82,613		2
					3
5,836		506	5,836		4
					5
22,356		506,588	22,356		6
					7
14,260		566	14,260		8
					9
56		566	56		10
					11
56		588	56		12
					13
631,847		506	631,847		14
6,881		506	6,881		15
					16
56,317		Various	56,317		17
					18
820,222			820,222		19
					20
					21
					22
					23
	119,768	506	119,768		24
	321,002	506	321,002		25
	1,188,856	506	1,188,856		26
	665,678	Various	665,678		27
	55,181	506	55,181		28
	561,614	Various	561,614		29
					30
	91,797	566,588	91,797		31
					32
	3,003,896		3,003,896		33
					34
					35
					36
					37
					38

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	45,862,900		
4	Transmission	2,525,808		
5	Regional Market			
6	Distribution	20,832,403		
7	Customer Accounts	11,352,933		
8	Customer Service and Informational	3,482,087		
9	Sales	968,710		
10	Administrative and General	8,509,560		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	93,534,401		
12	Maintenance			
13	Production	46,952,644		
14	Transmission	4,682,527		
15	Regional Market			
16	Distribution	23,105,489		
17	Administrative and General	2,853,329		
18	TOTAL Maintenance (Total of lines 13 thru 17)	77,593,989		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	92,815,544		
21	Transmission (Enter Total of lines 4 and 14)	7,208,335		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	43,937,892		
24	Customer Accounts (Transcribe from line 7)	11,352,933		
25	Customer Service and Informational (Transcribe from line 8)	3,482,087		
26	Sales (Transcribe from line 9)	968,710		
27	Administrative and General (Enter Total of lines 10 and 17)	11,362,889		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	171,128,390	8,257,845	179,386,235
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			

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)	171,128,390	8,257,845	179,386,235
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	56,900,076	2,745,728	59,645,804
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	56,900,076	2,745,728	59,645,804
72	Plant Removal (By Utility Departments)			
73	Electric Plant	13,455,733	649,310	14,105,043
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	13,455,733	649,310	14,105,043
77	Other Accounts (Specify, provide details in footnote):			
78	151 - Fuel Stock	-1,163		-1,163
79	152 - Fuel Stock Undistributed	10,523,666		10,523,666
80	154 - Materials & Supplies	-297		-297
81	163 - Stores Expense Undistributed	7,398,660	-7,398,660	
82	182 - Other Regulatory Assets	2,968	-2,968	
83	183 - Preliminary Survey	-14,364	14,364	
84	184 - Clearing Accounts	4,265,619	-4,265,619	
85	185 - ODD Temporary Facilites	156,880		156,880
86	186 - Misc Deferred Debits	5,937,795		5,937,795
87	188 - Research & Development	8,110		8,110
88	402 - Maintenance Exp	298		298
89	426 - Political Activities	47,642		47,642
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	28,325,814	-11,652,883	16,672,931
96	TOTAL SALARIES AND WAGES	269,810,013		269,810,013

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

COMMON UTILITY PLANT AND EXPENSES

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

Name of Respondent Ohio 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

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

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

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)				32,260,426
3	Net Sales (Account 447)				(96,648,898)
4	Transmission Rights				(5,461,296)
5	Ancillary Services				2,008,713
6	Other Items (list separately)				
7	Congestion				7,484,448
8	Operating Reserves				(3,598,539)
9	Transmission Purchase Expense				36,629
10	Transmission Losses				18,954,870
11	Meter Corrections				235,838
12	Inadvertent				54,278
13	Capacity Credits				(3,360,520)
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				(48,034,051)

Name of Respondent Ohio 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

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

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

Schedule Page: 398 Line No.: 1 Column: b

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

Name of Respondent Ohio 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

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

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

NAME OF SYSTEM:

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

Schedule Page: 400 Line No.: 1 Column: b

Ohio Power Company's transmission service is administered through an RTO/ISO and requested information is not available on an individual operating company basis.

Name of Respondent Ohio 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

MONTHLY ISO/RTO TRANSMISSION SYSTEM PEAK LOAD

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

NAME OF SYSTEM:

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

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

ELECTRIC ENERGY ACCOUNT

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

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	30,897,005
3	Steam	44,185,868			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	2,596,133
5	Hydro-Conventional	138,403			
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	30,029,692
7	Other	5,104,429			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	952
9	Net Generation (Enter Total of lines 3 through 8)	49,428,700	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
10	Purchases	17,646,286	27	Total Energy Losses	3,551,204
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	67,074,986
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)	67,074,986			

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

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM:

Line No.	Month	Total Monthly Energy	Monthly Non-Requirments Sales for Resale & Associated Losses	MONTHLY PEAK		
				Megawatts (See Instr. 4)	Day of Month	Hour
	(a)	(b)	(c)	(d)	(e)	(f)
29	January	6,334,808	2,412,004	7,880	13	1100
30	February	5,403,275	1,971,743	7,575	13	0800
31	March	5,005,802	1,756,893	7,266	5	2100
32	April	5,022,665	2,083,335	6,577	12	0800
33	May	5,247,590	2,053,167	8,122	25	1600
34	June	5,153,803	1,950,457	9,670	29	1400
35	July	6,596,739	2,950,351	9,578	18	1300
36	August	6,579,405	3,446,540	9,136	3	1500
37	September	5,044,422	2,623,268	8,626	6	1600
38	October	5,591,146	3,298,416	6,854	29	1900
39	November	5,227,095	2,928,093	6,971	28	2000
40	December	5,868,236	3,499,859	7,097	21	1800
41	TOTAL	67,074,986	30,974,126			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio 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: *AMOS-OPCO SHARE* (b)	Plant Name: *AMOS-TOTAL* (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	1973	1971
4	Year Last Unit was Installed	1973	1973
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	867.00	2933.00
6	Net Peak Demand on Plant - MW (60 minutes)	870	2900
7	Plant Hours Connected to Load	6067	6751
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	867	2900
10	When Limited by Condenser Water	867	2900
11	Average Number of Employees	99	333
12	Net Generation, Exclusive of Plant Use - KWh	3675995000	12969046000
13	Cost of Plant: Land and Land Rights	652289	5960346
14	Structures and Improvements	43728909	142064144
15	Equipment Costs	930279121	3086063540
16	Asset Retirement Costs	20345008	34950087
17	Total Cost	995005327	3269038117
18	Cost per KW of Installed Capacity (line 17/5) Including	1147.6417	1114.5715
19	Production Expenses: Oper, Supv, & Engr	1638545	7328288
20	Fuel	105975625	387920098
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	6994320	30315650
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	60297	231213
26	Misc Steam (or Nuclear) Power Expenses	711752	5309216
27	Rents	339	-30913
28	Allowances	70224	-75584
29	Maintenance Supervision and Engineering	835955	3334482
30	Maintenance of Structures	914577	3744080
31	Maintenance of Boiler (or reactor) Plant	7990136	37099334
32	Maintenance of Electric Plant	1094659	7763539
33	Maintenance of Misc Steam (or Nuclear) Plant	1842076	6761255
34	Total Production Expenses	128128505	489700658
35	Expenses per Net KWh	0.0349	0.0378

Line No.	Item (a)	(b)			(c)		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil		Coal	Oil	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Barrels		Tons	Barrels	
38	Quantity (Units) of Fuel Burned	1457609	27500	0	5241095	91162	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	12278	137121	0	12248	137108	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	69.234	138.120	0.000	69.618	138.152	0.000
41	Average Cost of Fuel per Unit Burned	67.770	137.288	0.000	68.425	137.374	0.000
42	Average Cost of Fuel Burned per Million BTU	2.760	23.838	0.000	2.793	23.856	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.027	0.000	0.000	0.028	0.000	0.000
44	Average BTU per KWh Net Generation	9785.000	0.000	0.000	9939.000	0.000	0.000

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: *CARDINAL-OPCO SHARE* (b)			Plant Name: *CARDINAL-TOTAL* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	STEAM			STEAM		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	PARTIAL OUTDOOR			PARTIAL OUTDOOR		
3	Year Originally Constructed	1967			1967		
4	Year Last Unit was Installed	1967			1977		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	615.00			1881.00		
6	Net Peak Demand on Plant - MW (60 minutes)	603			1829		
7	Plant Hours Connected to Load	5251			7335		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	595			1810		
10	When Limited by Condenser Water	585			1790		
11	Average Number of Employees	320			320		
12	Net Generation, Exclusive of Plant Use - KWh	2969568000			11901854000		
13	Cost of Plant: Land and Land Rights	417438			605833		
14	Structures and Improvements	43942040			102631627		
15	Equipment Costs	675193120			1868322229		
16	Asset Retirement Costs	12171475			12171475		
17	Total Cost	731724073			1983731164		
18	Cost per KW of Installed Capacity (line 17/5) Including	1189.7952			1054.6152		
19	Production Expenses: Oper, Supv, & Engr	878870			4160700		
20	Fuel	58653543			161785092		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	9988159			26509279		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	269200			825089		
26	Misc Steam (or Nuclear) Power Expenses	2637075			8940086		
27	Rents	0			0		
28	Allowances	318336			0		
29	Maintenance Supervision and Engineering	905792			2898236		
30	Maintenance of Structures	985695			3151992		
31	Maintenance of Boiler (or reactor) Plant	6414063			21566928		
32	Maintenance of Electric Plant	2959076			7869819		
33	Maintenance of Misc Steam (or Nuclear) Plant	864813			2578628		
34	Total Production Expenses	84874622			240285849		
35	Expenses per Net KWh	0.0286			0.0202		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil		Coal	Oil	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Barrels		Tons	Barrels	
38	Quantity (Units) of Fuel Burned	1111271	16647	0	2832888	79280	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	12416	137069	0	12335	137357	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	47.026	135.483	0.000	53.379	133.024	0.000
41	Average Cost of Fuel per Unit Burned	46.308	134.064	0.000	52.956	144.098	0.000
42	Average Cost of Fuel Burned per Million BTU	1.865	23.288	0.000	2.147	24.978	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.017	0.000	0.000	0.013	0.000	0.000
44	Average BTU per KWh Net Generation	9320.000	0.000	0.000	5914.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio 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: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
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

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Ohio 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: *CONESVILLE 5 & 6* (b)			Plant Name: *PICWAY* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	STEAM			STEAM		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	FULL OUTDOOR			OUTDOOR BOILER		
3	Year Originally Constructed	1957			1926		
4	Year Last Unit was Installed	1978			1955		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	888.00			106.25		
6	Net Peak Demand on Plant - MW (60 minutes)	920			97		
7	Plant Hours Connected to Load	7818			100		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	800			100		
10	When Limited by Condenser Water	800			95		
11	Average Number of Employees	300			4		
12	Net Generation, Exclusive of Plant Use - KWh	3307999000			3957000		
13	Cost of Plant: Land and Land Rights	236497			125244		
14	Structures and Improvements	59488899			6667669		
15	Equipment Costs	628332380			37247859		
16	Asset Retirement Costs	36925172			5820663		
17	Total Cost	724982948			49861435		
18	Cost per KW of Installed Capacity (line 17/5) Including	816.4222			469.2841		
19	Production Expenses: Oper, Supv, & Engr	2090576			338061		
20	Fuel	111552731			273542		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	14010796			96044		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	1115248			230527		
26	Misc Steam (or Nuclear) Power Expenses	11577768			302432		
27	Rents	0			0		
28	Allowances	1411888			2599		
29	Maintenance Supervision and Engineering	323901			50890		
30	Maintenance of Structures	592477			43195		
31	Maintenance of Boiler (or reactor) Plant	11991729			254524		
32	Maintenance of Electric Plant	2942587			30025		
33	Maintenance of Misc Steam (or Nuclear) Plant	862610			35859		
34	Total Production Expenses	158472311			1657698		
35	Expenses per Net KWh	0.0479			0.4189		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil		Coal	Oil	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Barrels		Tons	Barrels	
38	Quantity (Units) of Fuel Burned	1601727	6832	0	2840	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	11574	136599	0	11076	135800	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	57.762	130.727	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	57.809	58.120	0.000	76.915	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	2.497	10.130	0.000	3.472	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.028	0.000	0.000	0.055	0.000	0.000
44	Average BTU per KWh Net Generation	11220.000	0.000	0.000	16137.000	0.000	0.000

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Ohio 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: *CONESVILLE 4- TOTAL* (b)			Plant Name: *CONES 4 OPCO SHARE* (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	1973			1973		
4	Year Last Unit was Installed	-			-		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	841.50			366.05		
6	Net Peak Demand on Plant - MW (60 minutes)	785			375		
7	Plant Hours Connected to Load	3723			3723		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	780			339		
10	When Limited by Condenser Water	780			339		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	2481045000			999774000		
13	Cost of Plant: Land and Land Rights	74828			32550		
14	Structures and Improvements	40595999			17659259		
15	Equipment Costs	668481819			290789591		
16	Asset Retirement Costs	4278339			1861078		
17	Total Cost	713430985			310342478		
18	Cost per KW of Installed Capacity (line 17/5) Including	847.8087			847.8144		
19	Production Expenses: Oper, Supv, & Engr	0			839178		
20	Fuel	0			50016652		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			2353340		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			74271		
26	Misc Steam (or Nuclear) Power Expenses	0			5075692		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			91216		
30	Maintenance of Structures	0			212951		
31	Maintenance of Boiler (or reactor) Plant	0			5965977		
32	Maintenance of Electric Plant	0			988523		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			415069		
34	Total Production Expenses	0			66032869		
35	Expenses per Net KWh	0.0000			0.0660		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil		Coal	Oil	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Barrels		Tons	Barrels	
38	Quantity (Units) of Fuel Burned	1124299	1192	0	458210	519	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	11605	135976	0	12030	135976	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	79.697	0.000	0.000	78.958	0.000	0.000
41	Average Cost of Fuel per Unit Burned	83.732	119.597	0.000	83.291	119.562	0.000
42	Average Cost of Fuel Burned per Million BTU	3.608	20.941	0.000	3.462	20.935	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.038	0.000	0.000	0.038	0.000	0.000
44	Average BTU per KWh Net Generation	10525.000	0.000	0.000	11036.000	0.000	0.000

Name of Respondent Ohio 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

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: *SPORN-OPCO SHARE* (d)			Plant Name: *SPORN-TOTAL* (e)			Plant Name: *GAVIN* (f)			Line No.
		STEAM			STEAM			STEAM	1
		CONVENTIONAL			CONVENTIONAL			CONVENTIONAL	2
		1950			1950			1974	3
		1960			1960			1975	4
		305.00			610.00			2600.00	5
		288			579			2656	6
		6593			6593			7566	7
		0			0			0	8
		300			600			2640	9
		290			580			2640	10
		54			109			272	11
		585060000			988614000			17220105000	12
		101828			172464			2934019	13
		10980931			23886886			111174486	14
		141751812			267070534			1814739760	15
		15240772			25809548			23536298	16
		168075343			316939432			1952384563	17
		551.0667			519.5728			750.9171	18
		737986			1637944			4033791	19
		21767868			37794170			402439464	20
		0			0			0	21
		820318			1639158			62923290	22
		0			0			0	23
		0			0			0	24
		499264			998491			120370	25
		1935838			3295116			14914116	26
		26456			48146			0	27
		559966			592984			3211376	28
		129767			322643			1339515	29
		634775			1187321			2085358	30
		1718522			3847465			30568387	31
		618757			1441118			4017037	32
		645863			1140019			1306739	33
		30095380			53944575			526959443	34
		0.0514			0.0546			0.0306	35
Coal	Oil		Coal	Oil		Coal	Oil		36
Tons	Barrels		Tons	Barrels		Tons	Barrels		37
272670	3943	0	468195	8020	0	7196957	36511	0	38
11891	137293	0	11842	137089	0	11914	136839	0	39
73.077	132.876	0.000	73.651	133.638	0.000	55.110	133.643	0.000	40
71.479	128.797	0.000	71.924	129.062	0.000	53.380	127.832	0.000	41
3.006	22.336	0.000	3.037	22.415	0.000	2.240	22.242	0.000	42
0.033	0.000	0.000	0.034	0.000	0.000	0.022	0.000	0.000	43
11123.000	0.000	0.000	11315.000	0.000	0.000	9971.000	0.000	0.000	44

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: *MUSKINGUM* (d)	Plant Name: *MITCHELL* (e)	Plant Name: *KAMMER* (f)	Line No.
STEAM	STEAM	STEAM	1
CONVENTIONAL	OUTDOOR BOILER	CONVENTIONAL	2
1953	1971	1958	3
1968	1971	1959	4
1530.00	1633.00	713.00	5
958	1561	570	6
4487	6898	6284	7
0	0	0	8
1380	1560	630	9
1305	1560	585	10
134	231	60	11
1789615000	7544338000	1784836000	12
668886	1122477	165993	13
58753345	82827772	35122710	14
615471496	1669125486	299044158	15
31499602	2735918	4922286	16
706393329	1755811653	339255147	17
461.6950	1075.2062	475.8137	18
2038862	3020926	1012563	19
60887786	217183199	68551808	20
0	0	0	21
3169159	13072219	-439569	22
0	0	0	23
0	0	0	24
164731	816	7709	25
4318682	9220440	1161900	26
0	0	0	27
5887078	409820	2541935	28
230756	7108886	3860096	29
745257	1276367	374484	30
6122457	18948501	5925197	31
1318534	4571970	862448	32
790904	1048831	689538	33
85674206	275861975	84548109	34
0.0479	0.0366	0.0474	35

(d) Coal	(d) Oil	(d)	(e) Coal	(e) Oil	(e)	(f) Coal	(f) Oil	(f)	Line No.
Coal	Oil		Coal	Oil		Coal	Oil		36
Tons	Barrels		Tons	Barrels		Tons	Barrels		37
788796	21143	0	2986398	47110	0	913501	10161	0	38
12294	137075	0	12417	135816	0	11296	136519	0	39
84.143	124.442	0.000	70.254	140.800	0.000	69.514	141.365	0.000	40
71.854	125.408	0.000	68.529	135.109	0.000	69.305	140.717	0.000	41
2.922	21.783	0.000	2.759	23.686	0.000	3.068	24.542	0.000	42
0.032	0.000	0.000	0.027	0.000	0.000	0.035	0.000	0.000	43
10888.000	0.000	0.000	9866.000	0.000	0.000	11591.000	0.000	0.000	44

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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: (d)			Plant Name: (e)			Plant Name: (f)			Line No.
									1
									2
									3
									4
0.00			0.00			0.00			5
0			0			0			6
0			0			0			7
0			0			0			8
0			0			0			9
0			0			0			10
0			0			0			11
0			0			0			12
0			0			0			13
0			0			0			14
0			0			0			15
0			0			0			16
0			0			0			17
0			0			0			18
0			0			0			19
0			0			0			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
0			0			0			25
0			0			0			26
0			0			0			27
0			0			0			28
0			0			0			29
0			0			0			30
0			0			0			31
0			0			0			32
0			0			0			33
0			0			0			34
0.0000			0.0000			0.0000			35
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

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

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: BECKJORD-OPCO SHARE (d)	Plant Name: STUART-OPCO SHARE (e)	Plant Name: (f)	Line No.
STEAM	STEAM		1
CONVENTIONAL	SEMI-OUTDOOR		2
1969	1970		3
-	1974		4
57.60	634.61	0.00	5
51	589	0	6
5858	6983	0	7
0	0	0	8
49	600	0	9
48	600	0	10
0	0	0	11
226966000	2935173000	0	12
175499	1477657	0	13
1350619	25700424	0	14
17419320	513869627	0	15
225419	1050643	0	16
19170857	542098351	0	17
332.8274	854.2228	0	18
95538	1292107	0	19
6196985	90349865	0	20
0	0	0	21
-48711	4684053	0	22
0	0	0	23
0	0	0	24
34	419244	0	25
66246	3882719	0	26
0	-13189	0	27
0	0	0	28
80851	511820	0	29
88528	979399	0	30
348318	11609520	0	31
93721	4668072	0	32
198811	144217	0	33
7120321	118527827	0	34
0.0314	0.0404	0.0000	35

(d)			(e)			(f)			Line No.
Coal	Oil		Coal	Oil					36
Tons	Barrels		Tons	Barrels					37
99869	892	0	1244559	20474	0	0	0	0	38
12186	137303	0	11595	137400	0	0	0	0	39
56.225	136.528	0.000	59.601	135.749	0.000	0.000	0.000	0.000	40
57.556	112.177	0.000	59.981	135.131	0.000	0.000	0.000	0.000	41
2.362	19.452	0.000	2.586	23.416	0.000	0.000	0.000	0.000	42
0.025	0.000	0.000	0.025	0.000	0.000	0.000	0.000	0.000	43
10747.000	0.000	0.000	9873.000	0.000	0.000	0.000	0.000	0.000	44

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: *ZIMMER - OPCO SHARE* (d)	Plant Name: *WATERFORD* (e)	Plant Name: *DARBY* (f)	Line No.
STEAM	COMBINED CYCLE	GAS TURBINE	1
CONVENTIONAL	OUTDOOR HRSG	NO BOILER	2
1991	2003	2001	3
-	2003	2002	4
362.11	917.00	650.00	5
349	864	522	6
4407	7722	205	7
0	0	0	8
333	840	507	9
330	810	450	10
0	29	0	11
1142482000	5027420000	77009000	12
5959406	3000000	713584	13
169719335	14754445	3333937	14
632434386	202645686	186606092	15
396956	0	0	16
808510083	220400131	190653613	17
2232.7748	240.3491	293.3133	18
644530	1660291	945479	19
36539578	103753956	3446708	20
0	0	0	21
3804038	-933290	-670988	22
0	0	0	23
0	0	0	24
1445	-4	7	25
1747447	6506087	563602	26
0	0	34963	27
0	0	0	28
996080	332728	175814	29
1830282	501	15877	30
5866993	5304465	-28074	31
1722436	453289	668098	32
4310931	307	124069	33
57463760	117078330	5275555	34
0.0503	0.0233	0.0685	35

(d)			(e)			(f)			Line No.
Coal	Oil		Gas			Gas			36
Tons	Barrels		MCFs			MCFs			37
496611	21848	0	35748901	0	0	911229	0	0	38
11586	137712	0	1012000	0	0	1023000	0	0	39
57.452	130.187	0.000	2.894	0.000	0.000	3.677	0.000	0.000	40
57.339	129.164	0.000	2.893	0.000	0.000	3.677	0.000	0.000	41
2.474	22.332	0.000	2.859	0.000	0.000	3.594	0.000	0.000	42
0.025	0.000	0.000	0.021	0.000	0.000	0.044	0.000	0.000	43
10183.000	0.000	0.000	7196.000	0.000	0.000	12105.000	0.000	0.000	44

Schedule Page: 402 Line No.: -1 Column: b

Plant Name: Amos - This plant is owned jointly by Respondent and Appalachian Power Company, also a subsidiary of American Electric Power, Inc.

Schedule Page: 402 Line No.: -1 Column: d

Plant Name: Sporn - This plant is owned jointly by Respondent and Appalachian Power Company, also a subsidiary of American Electric Power, Inc.

Schedule Page: 402 Line No.: 20 Column: b

Expenses totaling $8,543,895 for deferred fuel and the Phase-in Recovery Rider are not included in the fuel totals that are broken down by generating plant.

Schedule Page: 402.1 Line No.: -1 Column: b

Plant Name: Cardinal - This plant is jointly owned by Respondent and Buckeye Power Company, a non-affiliate.

Schedule Page: 402.1 Line No.: -1 Column: e

Included in Mitchell Plant's investment are costs of $21,651(structures and improvements) and $13,203,231 (equipment). These amounts were paid by Ohio Power Company in gypsum unloading equipment located at Mountaineer Plant, which is owned and operated by Appalachian Power Company, a subsidiary of American Electric Power, Inc.

Schedule Page: 402.3 Line No.: -1 Column: b

Conesville Unit # 3 - Ohio Power Company retired December, 31, 2012. Lines 14 thru 17 do not include Conesville Unit # 3 cost data. Lines 19 thru 34 include Conesville Unit # 3 expense data prior to retirement.

Schedule Page: 402.3 Line No.: -1 Column: d

Beckjord Unit #6: This unit is commonly owned by Duke Energy, The Dayton Power and Light Company and the Respondent with undivided interests of 37.5%, 50.0% and 12.5%, respectively. Fuel expenses are shared on an energy received basis. All other expenses are shared on an ownership basis.

Schedule Page: 402.3 Line No.: -1 Column: e

Stuart: These units are commonly owned by Duke Energy, The Dayton Power and Light Company and the Respondent with undivided interests of 39%, 35% and 26%, respectively. Fuel expenses are shared on an energy received basis. All other expenses are shared on an ownership basis. (The diesel unit has been included with the steam unit as a Black Start Unit)

Schedule Page: 402.4 Line No.: -1 Column: b

Conesville Unit #4: This unit is commonly owned by Duke Energy,The Dayton Power and Light Company and the Respondent with undivided interests of 40.0%,16.5% and 43.5%, respectively. Fuel expenses are shared on an energy received basis. All other expenses are shared on an ownership basis.

Schedule Page: 402.4 Line No.: -1 Column: c

Conesville Unit #4 - Ohio Power Company Share: See footnote above.

Schedule Page: 402.4 Line No.: -1 Column: d

Zimmer: This unit is commonly owned by Duke Energy, The Dayton Power and Light Company and the Respondent with undivided interests of 46.5%, 28.1% and 25.4%, respectively. Fuel expenses are shared on an energy received basis. All other expenses are shared on an ownership basis.

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

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 2570 Plant Name: Racine (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	
2	Plant Construction type (Conventional or Outdoor)	Conventional Bulb	
3	Year Originally Constructed	1982	
4	Year Last Unit was Installed	1983	
5	Total installed cap (Gen name plate Rating in MW)	47.50	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	27	0
7	Plant Hours Connect to Load	8,273	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	48	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	4	0
12	Net Generation, Exclusive of Plant Use - Kwh	138,403,000	0
13	Cost of Plant		
14	Land and Land Rights	3,992	0
15	Structures and Improvements	49,979,341	0
16	Reservoirs, Dams, and Waterways	6,304,465	0
17	Equipment Costs	58,317,331	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	50,034	0
20	TOTAL cost (Total of 14 thru 19)	114,655,163	0
21	Cost per KW of Installed Capacity (line 20 / 5)	2,413.7929	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	69,431	0
24	Water for Power	29,229	0
25	Hydraulic Expenses	1,347	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	192,234	0
28	Rents	41,666	0
29	Maintenance Supervision and Engineering	952	0
30	Maintenance of Structures	123,198	0
31	Maintenance of Reservoirs, Dams, and Waterways	28,520	0
32	Maintenance of Electric Plant	326,918	0
33	Maintenance of Misc Hydraulic Plant	59,652	0
34	Total Production Expenses (total 23 thru 33)	873,147	0
35	Expenses per net KWh	0.0063	0.0000

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

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
			8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
			13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0.0000	0.0000	0.0000	21
			22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

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

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: (b)
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	
6	Plant Hours Connect to Load While Generating	
7	Net Plant Capability (in megawatts)	
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - Kwh	
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	
12	Cost of Plant	
13	Land and Land Rights	
14	Structures and Improvements	
15	Reservoirs, Dams, and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Powerplant Equipment	
19	Roads, Railroads, and Bridges	
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	
22	Cost per KW of installed cap (line 21 / 4)	
23	Production Expenses	
24	Operation Supervision and Engineering	
25	Water for Power	
26	Pumped Storage Expenses	
27	Electric Expenses	
28	Misc Pumped Storage Power generation Expenses	
29	Rents	
30	Maintenance Supervision and Engineering	
31	Maintenance of Structures	
32	Maintenance of Reservoirs, Dams, and Waterways	
33	Maintenance of Electric Plant	
34	Maintenance of Misc Pumped Storage Plant	
35	Production Exp Before Pumping Exp (24 thru 34)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per KWh (line 37 / 9)	

Name of Respondent Ohio 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

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. 0 Plant Name: (c)	FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	Line No.
			1
			2
			3
			4
			5
			6
			7
			8
			9
			10
			11
			12
			13
			14
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			21
			22
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			24
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			33
			34
			35
			36
			37
			38

Name of Respondent Ohio 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

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						
2						
3						
4						
5						
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14						
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Name of Respondent Ohio 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

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
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
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						43
						44
						45
						46

Name of Respondent Ohio 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

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	Ohio Power Company							
2	0168 BAKER	DON MARQUIS	765.00	765.00	AT	26.41		1
3	0168 BAKER	DON MARQUIS	765.00	765.00	ST	10.32		1
4	0171 KAMMER	DUMONT	765.00	765.00	AT	100.19		1
5	0171 KAMMER	DUMONT	765.00	765.00	ST	126.14		1
6	0194 AMOS	NORTH PROCTORVILLE	765.00	765.00	ST	5.30		1
7	0195 GAVIN	MARYSVILLE	765.00	765.00	ST	124.40		1
8	0232 AMOS	GAVIN	765.00	765.00	ST	0.49		1
9	0233 GAVIN	KAMMER	765.00	765.00	ST	2.62		1
10	0263 KAMMER	SOUTH CANTON	765.00	765.00	AT	0.24		1
11	0263 KAMMER	SOUTH CANTON	765.00	765.00	ST	78.44		1
12	0269 NORTH PROCTORV	HANGING ROCK	765.00	765.00	ST	25.99		1
13	0270 HANGING ROCK	JEFFERSON	765.00	765.00	ST	6.14		1
14	0047 SPORN	MUSKINGUM	345.00	345.00	ST	46.52		1
15	0048 MUSKINGUM	CENTRAL	345.00	345.00	ST	28.10		1
16	0048 MUSKINGUM	CENTRAL	345.00	345.00	ST	53.94		2
17	0052 CENTRAL	EAST LIMA	345.00	345.00	ST	2.68		1
18	0052 CENTRAL	EAST LIMA	345.00	345.00	ST	71.36		2
19	0070 EAST LIMA	SORENSON	345.00	345.00	ST	42.58		1
20	0079 MUSKINGUM	TIDD	345.00	345.00	ST	83.57		2
21	0088 KAMMER EXT. NO. 1		345.00	345.00	ST	0.20		1
22	0088 KAMMER EXT. NO. 1		345.00	345.00	ST	0.38		1
23	0104 TIDD	CANTON CENTRAL	345.00	345.00	AT	37.29		1
24	0104 TIDD	CANTON CENTRAL	345.00	345.00	ST	14.21		1
25	0106 CANTON CENTRAL	JUNIPER	345.00	345.00	AT	4.06		1
26	0106 CANTON CENTRAL	JUNIPER	345.00	345.00	ST	1.36		1
27	0106 CANTON CENTRAL	JUNIPER	345.00	345.00	ST	0.55		2
28	0119 MUSKINGUM	OHIO CENTRAL	345.00	345.00	AT	30.75		1
29	0119 MUSKINGUM	OHIO CENTRAL	345.00	345.00	ST	12.51		1
30	0142 KAMMER EXT. NO. 2		345.00	345.00	ST	0.15		1
31	0142 KAMMER EXT. NO. 2		345.00	345.00	ST	0.30		1
32	0161 OHIO CENTRAL	FOSTORIA CENTRAL	345.00	345.00	AT	100.53		1
33	0161 OHIO CENTRAL	FOSTORIA CENTRAL	345.00	345.00	ST	5.99		1
34	0162 FOSTORIA CENTRAL	EAST LIMA	345.00	345.00	AT	34.47		1
35	0162 FOSTORIA CENTRAL	EAST LIMA	345.00	345.00	ST	5.35		1
36					TOTAL	7,610.95	160.65	617

Name of Respondent Ohio 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

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 (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	0163 FOSTORIA CENTRAL	PEMBERVILLE	345.00	345.00	ST	19.29		2
2	0166 SOUTH CANTON	SAMMIS	345.00	345.00	ST	0.74		1
3	0167 SOUTH CANTON	STAR	345.00	345.00	ST	0.69		1
4	0172 SOUTHWEST LIMA		345.00	345.00	ST	14.68		2
5	0173 SOUTHWEST LIMA	MIAMI	345.00	345.00	AT	18.04		1
6	0173 SOUTHWEST LIMA	MIAMI	345.00	345.00	ST	0.97		1
7	0208 TIDD	COLIER	345.00	345.00	ST	0.31		2
8	0248 MARYSVILLE EXT NO		345.00	345.00	ST	4.22		2
9	0249 MARYSVILLE EXT NO		345.00	345.00	ST	4.84		2
10	0279 SOUTH CANTON	CANTON CENTRAL	345.00	345.00	ST	8.16		2
11	0365 WATERFORD	MUSKINGUM-SPORN	345.00	345.00	ST	0.98		
12	0366 BEVERLY EXTENSION		345.00	345.00	ST	0.10		
13	0001 LIMA	FT WAYNE	138.00	138.00	WP	0.10		2
14	0001 LIMA	FT WAYNE	138.00	138.00	ST	43.58		2
15	0004 HOWARD	ASHLAND	138.00	138.00	ST	6.15		1
16	0004 HOWARD	ASHLAND	138.00	138.00	ST	1.84		2
17	0005 WINDSOR	CANTON	138.00	138.00	ST	54.39		1
18	0005 WINDSOR	CANTON	138.00	138.00	WP	0.08		1
19	0006 WINDSOR	CANTON (WV)	138.00	138.00	ST	0.32		1
20	0007 PHILO	HOWARD	138.00	138.00	WP	0.05		2
21	0007 PHILO	HOWARD	138.00	138.00	ST	80.73		2
22	0010 FOSTORIA	PEMBERVILLE	138.00	138.00	ST	18.49		2
23	0010 FOSTORIA	PEMBERVILLE	138.00	138.00	ST	0.06		1
24	0010 FOSTORIA	PEMBERVILLE	138.00	138.00	WP			1
25	0011 PHILO	RUTLAND	138.00	138.00	ST	65.70		2
26	0016 SOUTH POINT	TURNER	138.00	138.00	ST	0.48		2
27	0018 PHILO	TORREY	138.00	138.00	ST	70.73		1
28	0019 CROOKSVILLE	WEST LANCASTER	138.00	138.00	ST	30.70		2
29	0020 PHILO	CANTON	138.00	138.00	ST	74.04		1
30	0025 TIDD	WAGENHALS	138.00	138.00	ST	53.45		1
31	0028 PORTSMOUTH	TRENTON NO. 2	138.00	138.00	WP	67.70		1
32	0028 PORTSMOUTH	TRENTON NO. 2	138.00	138.00	ST	0.24		1
33	0028 PORTSMOUTH	TRENTON NO. 2	138.00	138.00	ST	0.45		2
34	0032 TRENTON	MUNCIE	138.00	138.00	ST	24.62		1
35	0033 RUTLAND	SPORN	138.00	138.00	ST	4.81		2
36					TOTAL	7,610.95	160.65	617

Name of Respondent Ohio 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

TRANSMISSION LINE STATISTICS

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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	0034 SPORN	SOUTH POINT	138.00	138.00	ST	9.22		1
2	0034 SPORN	SOUTH POINT	138.00	138.00	ST	40.41		2
3	0036 SPORN	PORTSMOUTH	138.00	138.00	ST	0.05		1
4	0036 SPORN	PORTSMOUTH	138.00	138.00	ST	48.76		2
5	0037 HILLSBORO	MAYSVILLE	138.00	138.00	ST	33.65		1
6	0038 CROOKSVILLE	NORTH NEWARK	138.00	138.00	WP	30.67		1
7	0038 CROOKSVILLE	NORTH NEWARK	138.00	138.00	ST	0.58		2
8	0039 WEST LANCASTER	SOUTH BALTIMORE	138.00	138.00	WP	9.82		1
9	0041 NORTH NEWARK	WEST MT. VERNON	138.00	138.00	WP	20.28		1
10	0041 NORTH NEWARK	WEST MT. VERNON	138.00	138.00	ST	1.48		2
11	0042 SOUTH BALTIMORE	NORTH NEWARK	138.00	138.00	WP	21.04		1
12	0042 SOUTH BALTIMORE	NORTH NEWARK	138.00	138.00	ST	0.05		1
13	0042 SOUTH BALTIMORE	NORTH NEWARK	138.00	138.00	ST	0.08		2
14	0043 BELLEFONTE EXT.		138.00	138.00	ST	2.80		2
15	0044 SUMMERFIELD	NATRIUM	138.00	138.00	ST	27.07		2
16	0045 PHILO	MUSKINGUM	138.00	138.00	ST	23.16		2
17	0046 MUSKINGUM	SUMMERFIELD	138.00	138.00	ST	25.31		2
18	0049 FOSTORIA	EAST LIMA	138.00	138.00	WP	0.06		1
19	0049 FOSTORIA	EAST LIMA	138.00	138.00	ST	40.77		2
20	0050 EAST LIMA	LIMA	138.00	138.00	ST	4.43		2
21	0055 TORREY	WOOSTER	138.00	138.00	WP	26.39		1
22	0055 TORREY	WOOSTER	138.00	138.00	ST	2.30		1
23	0056 WEST MT. VERNON	SOUTH KENTON	138.00	138.00	WP	59.06		1
24	0057 SOUTH KENTON	STERLING	138.00	138.00	ST	0.09		1
25	0057 SOUTH KENTON	STERLING	138.00	138.00	WP	28.31		1
26	0058 SOUTH POINT	PORTSMOUTH	138.00	138.00	ST	0.04		1
27	0058 SOUTH POINT	PORTSMOUTH	138.00	138.00	ST	34.57		2
28	0059 PHILO	CROOKSVILLE	138.00	138.00	ST	15.37		2
29	0060 LIMA	STERLING	138.00	138.00	WP	1.89		1
30	0060 LIMA	STERLING	138.00	138.00	ST	4.07		1
31	0061 EAST LIMA	WEST LIMA	138.00	138.00	WP	0.15		2
32	0061 EAST LIMA	WEST LIMA	138.00	138.00	ST	11.19		2
33	0061 EAST LIMA	WEST LIMA	138.00	138.00	ST	1.05		3
34	0063 TORREY	MASSILLON	138.00	138.00	ST	0.29		2
35								
36					TOTAL	7,610.95	160.65	617

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

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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 (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	0066 WAGENHALS	WEST CANTON	138.00	138.00	ST	9.16		1
2	0066 WAGENHALS	WEST CANTON	138.00	138.00	ST	0.85		2
3	0067 TORREY	AKRON	138.00	138.00	ST	0.28		1
4	0069 TIDD	SOUTH CADIZ	138.00	138.00	WP	16.59		1
5	0071 AKRON	CANTON	138.00	138.00	ST	3.75		1
6	0072 TIDD	WEIRTON NO. 2	138.00	138.00	WP	6.21		1
7	0072 TIDD	WEIRTON NO. 2	138.00	138.00	ST	0.05		1
8	0073 WEIRTON	SOUTH TORONTO	69.00	138.00	ST	0.48		2
9	0073 WEIRTON	SOUTH TORONTO	138.00	138.00	ST	0.14		1
10	0075 SPORN	KAISER NO. 1	138.00	138.00	ST	4.25		2
11	0076 LUCASVILLE	SARGENTS	138.00	138.00	WP	11.88		1
12	0078 TIDD	WINDSOR JCT.	138.00	138.00	ST	3.77		1
13	0080 NEWCOMERSTOWN	SOUTH COSHOCTON	138.00	138.00	WP	14.33		1
14	0081 FORD MOTOR EXT		138.00	138.00	ST	0.25		2
15	0086 SPORN	KAISER NO. 2	138.00	138.00	ST	5.67		2
16	0087 WINDSOR JUNCTION	TILTONVILLE	138.00	138.00	ST	3.81		1
17	0087 WINDSOR JUNCTION	TILTONVILLE	138.00	138.00	ST	0.30		2
18	0089 WEST PHILO EXT. NO.		138.00	138.00	WP	0.05		1
19	0090 WEST PHILO EXT. NO.		138.00	138.00	WP	0.13		1
20	0091 KAMMER	OHIO FERRO ALLOYS	138.00	138.00	WP	2.45		1
21	0091 KAMMER	OHIO FERRO ALLOYS (WV)	138.00	138.00	ST	0.71		1
22	0095 PORTSMOUTH	TRENTON NO. 1	138.00	138.00	WP	68.24		1
23	0095 PORTSMOUTH	TRENTON NO. 1	138.00	138.00	ST	1.04		1
24	0095 PORTSMOUTH	TRENTON NO. 1	138.00	138.00	ST	0.24		2
25	0096 THIVENER	BUCKEYE CO-OP	138.00	138.00	WP	6.16		1
26	0097 MERCERVILLE	APPLE GROVE	138.00	138.00	ST	5.11		2
27	0098 MILLWOOD EXT.		138.00	138.00	WP	0.10		1
28	0101 THIVENER EXT.		138.00	138.00	WP	0.09		1
29	0102 MEIGS EXT. NO. 1		138.00	138.00	WP	0.10		1
30	0103 MEIGS EXT NO. 2		138.00	138.00	WP	0.10		1
31	0103 MEIGS EXT NO. 2		138.00	138.00	ST	0.07		1
32	0108 OHIO CENTRAL	NORTH NEWARK	138.00	138.00	ST	0.33		2
33	0108 OHIO CENTRAL	NORTH NEWARK	138.00	138.00	WP	21.30		1
34	0110 NORTH STRASBURG		138.00	138.00	WP	0.06		1
35	0111 NORTH STRASBURG		138.00	138.00	WP	0.06		1
36					TOTAL	7,610.95	160.65	617

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	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	0112 ZANESVILLE EXT.		138.00	138.00	ST	6.48		2
2	0113 HOWARD	BUCYRUS CENTER	138.00	138.00	ST	16.30		1
3	0113 HOWARD	BUCYRUS CENTER	138.00	138.00	ST	0.27		2
4	0114 SOUTH PEMBERVILLE	FREEMONT	138.00	138.00	WP	14.18		1
5	0114 SOUTH PEMBERVILLE	FREEMONT	138.00	138.00	ST	1.29		2
6	0115 SUMMERFIELD	BERNE	138.00	138.00	WP	3.46		1
7	0118 SOUTH COSHOCTON	WOOSTER	138.00	138.00	WP	39.51		1
8	0120 OHIO CENTRAL	COSHOCTON JCT.	138.00	138.00	ST	0.20		1
9	0120 OHIO CENTRAL	COSHOCTON JCT.	138.00	138.00	ST	14.52		2
10	0122 KAMMER	ORMET NO. 1	138.00	138.00	ST	1.71		2
11	0123 FINDLAY CENTER EXT.		138.00	138.00	ST	6.66		1
12	0125 TIDD	WEIRTON NO. 1	138.00	138.00	ST	0.41		2
13	0126 ARROYO	EAST LIVERPOOL	138.00	138.00	ST	0.15		1
14	0128 TIDD	NATRIUM	138.00	138.00	ST	0.26		1
15	0129 HOWARD	FOSTORIA	138.00	138.00	ST	0.50		1
16	0129 HOWARD	FOSTORIA	138.00	138.00	ST	44.38		2
17	0130 EAST WHEELERSB	TEXAS EASTERN	138.00	138.00	WP	1.99		1
18	0131 KAMMER	ORMET NO. 2	138.00	138.00	ST	1.55		2
19	0133 SUNNYSIDE	WAGENHALS NO. 1	138.00	138.00	ST	1.44		1
20	0133 SUNNYSIDE	WAGENHALS NO. 1	138.00	138.00	WP	2.23		1
21	0134 TIDD	WHEELING STEEL	138.00	138.00	ST	5.12		2
22	0141 MILLBROOK	SILOAM	138.00	138.00	ST	1.60		2
23	0141 MILLBROOK	SILOAM	138.00	138.00	SP	0.05		1
24	0143 ZANESVILLE	OHIO CENTRAL	138.00	138.00	WP	10.96		1
25	0143 ZANESVILLE	OHIO CENTRAL	138.00	138.00	ST	1.87		1
26	0144 TORREY	TIMKEN	138.00	138.00	WP	0.80		1
27	0144 TORREY	TIMKEN	138.00	138.00	ST	0.86		1
28	0145 CANTON CENTRAL	TIMKEN	138.00	138.00	SP	0.74		1
29	0145 CANTON CENTRAL	TIMKEN	138.00	138.00	ST	5.52		1
30	0146 EAST LIMA	WESTMINSTER	138.00	138.00	ST	8.38		2
31	0147 SUNNYSIDE	WAGENHALS NO. 2	138.00	138.00	WP	2.21		1
32	0149 CANTON CENTRAL	WAGENHALS	138.00	138.00	ST	2.02		2
33	0151 SOUTH CANTON	TORREY	138.00	138.00	ST	1.26		1
34	0151 SOUTH CANTON	TORREY	138.00	138.00	ST	1.60		2
35	0152 MALAGA	SPEIDEL	69.00	138.00	WP	11.99		1
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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	0153 BRIDGEVILLE EXT.		138.00	138.00	WP	1.88		1
2	0156 TIFFIN CENTER EXT.		138.00	138.00	WP	5.34		1
3	0156 TIFFIN CENTER EXT.		69.00	138.00	WP	1.81		2
4	0158 ROBINSON PARK	RICHLAND	138.00	138.00	WP	14.94		1
5	0159 EAST LIMA	RICHLAND	138.00	138.00	WP	27.74		1
6	0164 FOSTORIA CENTRAL	FOSTORIA	138.00	138.00	ST	0.08		1
7	0164 FOSTORIA CENTRAL	FOSTORIA	138.00	138.00	ST	1.48		2
8	0169 SOUTH CALDWELL	SOUTH CUMBERLAND	138.00	138.00	WP	10.86		1
9	0170 HANGING ROCK EXT.		138.00	138.00	ST	4.33		1
10	0174 CANTON CENTRAL	BLUEBELL	138.00	138.00	WP	0.36		1
11	0175 CANTON CENTRAL	CLOVERDALE	138.00	138.00	WP	0.38		1
12	0176 TIDD	STEUBENVILLE	138.00	138.00	ST	7.30		1
13	0177 SOUTHWEST LIMA	STERLING	138.00	138.00	ST	5.14		2
14	0177 SOUTHWEST LIMA	STERLING	34.00	138.00	WP	0.18		2
15	0177 SOUTHWEST LIMA	STERLING	138.00	138.00	SP	0.02		1
16	0177 SOUTHWEST LIMA	STERLING	138.00	138.00	WP	0.03		1
17	0178 SOUTHWEST LIMA	WEST LIMA	138.00	138.00	ST	0.88		2
18	0180 OHIO CENTRAL EXT		138.00	138.00	WP	0.46		1
19	0181 OHIO CENTRAL EXT		138.00	138.00	WP	0.45		1
20	0182 SOUTH CANTON	WEST CANTON	138.00	138.00	SP	5.20		2
21	0182 SOUTH CANTON	WEST CANTON	138.00	138.00	ST	2.59		1
22	0182 SOUTH CANTON	WEST CANTON	138.00	138.00	ST	2.26		2
23	0183 KAMMER	WEST BELLAIRE	138.00	138.00	ST	12.85		1
24	0183 KAMMER	WEST BELLAIRE	69.00	138.00	ST	0.33		2
25	0186 EAST ZANESVILLE		138.00	138.00	WP	0.04		1
26	0187 WEST BELLAIRE	BRUES	138.00	138.00	ST	4.26		1
27	0188 WEST BELLAIRE	TILTONVILLE	138.00	138.00	WP	11.49		1
28	0188 WEST BELLAIRE	TILTONVILLE	138.00	138.00	ST	0.50		1
29	0189 CROOKSVILLE TIE		138.00	138.00	WP	0.20		1
30	0190 SOUTHWEST LIMA	WEST MOULTON	138.00	138.00	WP	13.33		1
31	0193 TIFFIN CENTER	FREMONT CENTER	138.00	138.00	WP	11.84		1
32	0193 TIFFIN CENTER	FREMONT CENTER	138.00	138.00	ST	0.70		1
33	0193 TIFFIN CENTER	FREMONT CENTER	138.00	138.00	ST	0.04		2
34	0196 FREMONT CENTER	FREMONT	138.00	138.00	WP	3.02		1
35	0196 FREMONT CENTER	FREMONT	138.00	138.00	ST	2.68		1
36					TOTAL	7,610.95	160.65	617

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

TRANSMISSION LINE STATISTICS

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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	0198 N. PROCTORVILLE	EAST HUNTINGTON	138.00	138.00	ST	3.86		1
2	0198 N. PROCTORVILLE	EAST HUNTINGTON	34.00	138.00	ST	0.08		2
3	0200 CAMPBELL ROAD	MIDWEST CO-OP	138.00	138.00	WP	0.15		1
4	0201 N. PROCTORVILLE	SOUTH POINT	138.00	138.00	ST	0.04		1
5	0201 N. PROCTORVILLE	SOUTH POINT	138.00	138.00	ST	10.83		2
6	0202 MUSKINGUM	WOLF CREEK	138.00	138.00	WP	3.65		1
7	0202 MUSKINGUM	WOLF CREEK	138.00	138.00	ST	1.06		1
8	0203 SWITZER EXT. NO. 1		138.00	138.00	WP	0.04		1
9	0204 SWITZER EXT. NO. 2		138.00	138.00	WP	0.06		1
10	0210 BUCKLEY ROAD EXT.		138.00	138.00	SP	0.09		1
11	0210 BUCKLEY ROAD EXT.		138.00	138.00	WP	2.62		1
12	0213 WINDSOR EXT. NO. 2			138.00	WP	0.11		1
13	0221 DARRAH	NORTH PROCTORVILLE	138.00	138.00	ST	3.51		1
14	0223 DEXTER	MEIGS NO. 2	138.00	138.00	WP	5.53		1
15	0224 NORTH RUTLAND	MEIGS NO. 1	138.00	138.00	WP	3.84		1
16	0225 AMITY	ACADEMIA	138.00	138.00	ST	0.14		1
17	0225 AMITY	ACADEMIA	138.00	138.00	ST	6.33		2
18	0226 ACADEMIA	WEST MT. VERNON	138.00	138.00	ST	0.15		2
19	0226 ACADEMIA	WEST MT. VERNON	138.00	138.00	ST	5.95		1
20	0229 CANNELVILLE	GURNSEY MUSKINGUM C	138.00	138.00	WP	0.11		1
21	0230 FAIRCREST EXT.		138.00	138.00	SP	0.04		1
22	0235 WEST MILLERSPORT	HEATH	138.00	138.00	WP	8.95		1
23	0235 WEST MILLERSPORT	HEATH	138.00	138.00	ST	3.06		1
24	0238 NORTH	EXTENSION	138.00	138.00	ST	3.54		1
25	0240 NORTH CROWN CITY		138.00	138.00	WP	0.24		1
26	0241 NORTH CROWN CITY		138.00	138.00	WP	0.24		1
27	0242 HEATH EXT. NO. 2		138.00	138.00	ST	1.29		1
28	0243 HEATH EXT. NO. 1		138.00	138.00	ST	1.29		1
29	0244 EAST SIDE EXT.		138.00	138.00	WP	0.24		2
30	0244 EAST SIDE EXT.		138.00	138.00	ST	0.08		2
31	0245 SOUTHEAST CANTON	SUNNYSIDE	138.00	138.00	ST	2.31		2
32	0247 SOUTHEAST CANTON	WACO	138.00	138.00	ST	2.12		2
33	0252 WEST DOVER EXT.		138.00	138.00	WP	0.10		1
34	0253 WEST DOVER EXT.		138.00	138.00	WP	0.09		1
35	0254 BUCKEYE CO-OP EXT.		138.00	138.00	WP	0.21		1
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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	0257 GREENLAWN EXT.		138.00	138.00	WP	1.09		2
2	0260 EAST PROCTORVILLE		138.00	138.00	ST	0.13		2
3	0264 FREMONT	SANDUSKY BAY	69.00	138.00	WP	12.13		1
4	0265 WEST DOVER	SUGARCREEK	138.00	138.00	WP	4.07		1
5	0267 NORTH PORTSMOUTH	CENTRAL PORTSMOUTH	138.00	138.00	WP	6.04		1
6	0273 BUCKLEY ROAD	FREMONT CENTER	69.00	138.00	WP	0.90		2
7	0274 WAYVIEW	HOOVER NORTH	69.00	138.00	ST	0.02		1
8	0274 WAYVIEW	HOOVER NORTH	69.00	138.00	ST	1.04		2
9	0275 WEST CANTON JCT.	WAYVIEW	138.00	138.00	WP	1.11		1
10	0275 WEST CANTON JCT.	WAYVIEW	138.00	138.00	SP	1.80		2
11	0275 WEST CANTON JCT.	WAYVIEW	138.00	138.00	ST	1.89		1
12	0276 BELDEN VILLAGE EXT.		138.00	138.00	SP	1.51		1
13	0280 EAST AMSTERDAM	CARROLL CO-OP	69.00	138.00	WP	7.98		1
14	0282 SOUTH POINT TIE		138.00	138.00	WP	0.09		1
15	0286 WEST CANTON TIE		138.00	138.00	SP	0.07		2
16	0289 OHIO CENTRAL EXT.		138.00	138.00	WP	0.27		1
17	0290 SOUTH CANTON EXT.		138.00	138.00	ST	0.71		2
18	0294 SOUTH CANTON EXT.		138.00	138.00	ST	0.31		2
19	0295 BROADACRE EXT.		138.00	138.00	SP	0.04		2
20	0307 WEST VAN WERT	DELPHOS CENTER	69.00	138.00	WP	1.70		1
21	0313 BUCKEYE COOP EXT.		138.00	138.00	WP	0.85		1
22	0316 ORDANANCE JCT.		138.00	138.00	SP	0.10		2
23	0317 GUERNSEY	MUSKINGUM CO-OP EXT.	138.00	138.00	WP	0.12		1
24	0318 BUCKEYE CO-OP EXT.		138.00	138.00	WP	0.15		1
25	0320 HEDDING ROAD	MORROW CO-OP	138.00	138.00	WP	0.09		1
26	0324 WEST MILLERSPORT	SOUTH CENTRAL POWER	138.00	138.00	WP	0.20		1
27	0325 SHELBY MUNICIPAL		138.00	138.00	ST	0.53		1
28	0326 BLOOMFIELD	GUERNSEY MUSKINGUM C	138.00	138.00	WP	0.41		1
29	0327 NORTH CENTRAL		138.00	138.00	WP	0.45		1
30	0328 NORTH CHESIRE	EXTENSION NO. 2	138.00	138.00				
31	0329 TYCOON EXT.		138.00	138.00	WP	0.29		1
32	0331 LICKING CO-OP EXT.		138.00	138.00	WP	0.04		1
33	0333 ASHLEY EXT		69.00	138.00	WP	0.62		1
34	0334 NORTH CHESIRE	EXTENTION NO. 1	138.00	138.00	ST	0.38		2
35	0336 SHUFFEL ROAD	TIMKEN RESEARCH	69.00	138.00	ST	0.66		1
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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	0337 TIMKEN, RICHVILLE EX		138.00	138.00	WP	1.11		2
2	0338 CONESVILLE COAL		138.00	138.00	WP	0.63		1
3	0339 A.G.A. GAS EXT.		138.00	138.00	WP	0.16		1
4	0342 EAST WOOSTER EXT.		138.00	138.00	ST	5.15		2
5	0343 EAST WOOSTER EXT.		138.00	138.00	WP	0.18		1
6	0343 EAST WOOSTER EXT.		138.00	138.00	WP	0.43		2
7	0344 WAGENHALS	LTV STEEL NO. 1	138.00	138.00	ST	0.65		1
8	0345 WAGENHALS	LTV STEEL NO. 2	138.00	138.00	ST	0.68		1
9	0346 FOSTORIA TIE		138.00	138.00	WP	0.02		1
10	0347 FOSTORIA CENTRAL		138.00	138.00	ST	0.10		2
11	0348 FOSTORIA CENTRAL		138.00	138.00	ST	0.10		1
12	0349 FOSTORIA POWER		138.00	138.00	ST	0.10		3
13	0350 HANCOCK WOOD		138.00	138.00	WP	0.03		1
14	0351 EAST LEIPSIC EXT		138.00	138.00	SP	6.57		2
15	0352 BUCKEYE CO-OP EXT		138.00	138.00	WP	0.09		1
16	0353 STERLING	FOUNDRY PARK	138.00	138.00	WP	0.91		1
17	0354 GAVIN EXT. NO. 1		138.00	138.00	ST	3.10		2
18	0355 GAVIN EXT. NO. 2		138.00	138.00	ST	3.01		2
19	0358 LICKING REC. EXT. A		138.00	138.00	WP	0.24		1
20	0359 BUCKHORN	HOLMES	138.00	138.00	WP	0.98		1
21	0360 ADAMS RUAL	EMERALD	138.00	138.00	WP	0.80		1
22	0361 RILEY CREEK	PAULDING PUTNAM	138.00	138.00	ST	1.20		1
23	0363 MEIGS NO. 2	WILKESVILLE	138.00	138.00		1.60		1
24	0364 NORTH CENTRAL		138.00	138.00		1.84		1
25	0368 BALL HOLLOW	WASHINGTON CO-OP	138.00	138.00		0.05		1
26	0371 SPENCER RIDGE	BUCKINGHAM COAL	138.00	138.00	WP	0.12		1
27	0370 BUCKEYE CO-OP EXT		138.00	138.00	ST	0.10		2
28	0372 NORTH BELLVILLE		138.00	138.00	WP	0.11		2
29	0375 HANTHORN RD	G.O. ETHANOL		138.00	ST	0.34		1
30	0376 WARNER EXTENSION	SUNNYSIDE-TORREY	138.00	138.00	WP	0.30		1
31	0377 YELLOWBUSH		138.00	138.00	ST	0.04		1
32	LINES < 132KV					2,449.21		
33								
34								
35								
36					TOTAL	7,610.95	160.65	617

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1	Columbus Southern Power Co							
2	FULLY OWNED TRANS							
3	BEATTY	HAYDEN	345.00	345.00	1			1
4	9032 BEATTY	HAYDEN	345.00	345.00	3	17.00		1
5	9034 CONESVILLE	CORRIDOR	345.00	345.00	3	54.00		1
6	C633 POINT N	STR. 96-1	345.00	345.00	1,3	4.24		1
7	HAYDEN	HYATT	345.00	345.00	1			1
8	HAYDEN	HYATT	345.00	345.00	2			1
9	9037 HAYDEN	HYATT	345.00	345.00	3	12.00		1
10	9038 HAYDEN	ROBERTS	345.00	345.00	1	11.53		1
11	9039 POINT Z HYATT	CORRIDOR	345.00	345.00	3	13.00		1
12	C613 KIRK EXT #1 (NORTH)		345.00	345.00	1	0.25		1
13	C614 KIRK EXT #2 (SOUTH)		345.00	345.00	1	0.25		1
14	8790 DAVIDSON	DUBLIN	138.00	138.00	4	3.16		1
15	C710 DUBLIN	SAWMILL	138.00	138.00	1	6.40		1
16	C795 KIMBERLY		138.00	138.00	1	0.56		2
17	C796 DON MARQUIS LOOP		138.00	138.00	1	6.60		1
18	C798 DON MARQUIS LOOP		138.00	138.00	1	0.65		1
19	C799 GREIF EXTENSION		138.00	138.00	4	0.66		2
20	C800 LICK	JACKSON	138.00	138.00	1	1.09		
21	C850 WILLOW ISLAND	MILL CREEK	138.00	138.00	1	9.14		1
22	C851 MILL CREEK	RIVERVIEW	138.00	138.00	1	10.80		1
23	C852 RIVERVIEW	CORNER	138.00	138.00	1	7.09		1
24	C853 CORNER	SHELL	138.00	138.00	1	2.13		1
25	C854 PARKERSBURG	CORNER	138.00	138.00	1	7.67		1
26	C855 MUSKINGUM	CORNER	138.00	138.00	1	15.79		1
27	C856 BELMONT	RIVERVIEW	138.00	138.00	1	0.86		1
28	C857 WASHINGTON	CORNER	138.00	138.00	1	6.51		1
29	C858 RIVERVIEW	ELKEM METALS	138.00	138.00	1	0.80		1
30	COMMONLY OWNED: (A)							
31	9001 BECKJORD	PIERCE	345.00	345.00	3			1
32	9002 PIERCE	FOSTER	345.00	345.00	3	24.00		1
33	9006 GREENE	BEATTY	345.00	345.00	3	49.00		1
34	9007 MARQUIS	POINT X	345.00	345.00	3	46.00		1
35	9009 STUART	GREENE	345.00	345.00	3	79.00		1
36					TOTAL	7,610.95	160.65	617

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1	9010 STUART	POINT M-KILLEN	345.00	345.00	3	13.00		1
2	STUART	FOSTER	345.00	345.00	3	55.00		1
3	9011 STUART	FOSTER	345.00	345.00	3	1.00		1
4	9041 STUART	ZIMMER	345.00	345.00	3	35.00		1
5	9044 ZIMMER	PORT UNION	345.00	345.00	3	10.00		1
6	9049 KILLEN-POINT O	MARQUIS	345.00	345.00				
7	POINT O-KILLEN	MARQUIS	345.00	345.00	3	32.00		1
8	POINT Y	BEATTY	345.00	345.00	3	15.00		1
9	9742 POINT Y	BEATTY	345.00	345.00	3		4.00	1
10	COMMONLY OWNED: (B)							
11	9031 BEATTY	BIXBY	345.00	345.00	3	13.00		1
12	STUART	TOWER 2	345.00	345.00	3			1
13	9042 TOWER 2	POINT Y	345.00	345.00	3	75.00		1
14	CONESVILLE	TOWER 71	345.00	345.00	2	51.00		1
15	9043 TOWER 71	BIXBY	345.00	345.00	3		15.00	1
16	POINT X	TOWER 27	345.00	345.00	3	17.00		1
17	9707 TOWER 27	BIXBY	345.00	345.00	3		9.00	1
18	COMMONLY OWNED: (C)							
19	9040 CONESVILLE	POINT Z	345.00	345.00	3	57.00		1
20	COMMONLY OWNED: (D)							
21	POINT Z	HYATT	345.00	345.00	3	9.00		1
22	POINT Z	HYATT	345.00	345.00	1	2.00		1
23	9740 POINT Z	HYATT	345.00	345.00	2			1
24	COMMONLY OWNED: (E)							
25	STUART	ZIMMER	345.00	345.00	3	1.00		1
26	9045 ZIMMER-SILVER	RED BANK	345.00	345.00	3	33.00	2.00	1
27	9145 ZIMMER-SILVER	RED BANK	345.00	345.00	3			1
28	9046 RED BANK	TERMINAL	345.00	345.00	3	7.00		1
29	9053 ZIMMER	PIERCE	345.00	345.00	3	1.00	36.00	1
30	ROBERTS	BETHEL	138.00	138.00	1			2
31	8001 ROBERTS	BETHEL	138.00	138.00	3	5.00		2
32	8002 ROBERTS	KENNY	138.00	138.00	4	3.00		1
33	C789 BEAVER 138KV		138.00	138.00				
34	BETHEL	LINWORTH	138.00	138.00	3		3.00	1
35	8004 BETHEL	LINWORTH	138.00	138.00	1	2.00		1
36					TOTAL	7,610.95	160.65	617

Name of Respondent Ohio 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

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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)	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)	On Structures of Another Line (g)	Number Of Circuits (h)
1	8005 PICWAY	HARRISON	138.00	138.00	3	1.00		1
2	8008 GROVES	BEXLEY	138.00	138.00	1	4.00		1
3	8009 BEXLEY	ST. CLAIR	138.00	138.00	1	4.00		1
4	BIXBY	LSII	138.00	138.00	1	1.00	2.00	1
5	BIXBY	LSII	138.00	138.00	2	2.00		1
6	8010 BIXBY	LSII	138.00	138.00	3			1
7	BIXBY	W. LANCASTER	138.00	138.00	2	18.00		1
8	BIXBY	W. LANCASTER	138.00	138.00	2			1
9	8011 BIXBY	W. LANCASTER	138.00	138.00	2	1.00		1
10	POSTON	ROSS	138.00	138.00	2	42.00		1
11	8012 POSTON	ROSS	138.00	138.00	3	1.00		1
12	8013 ROSS	DELANO	138.00	138.00	2	5.00		1
13	8013 ROSS	DELANO	138.00	138.00	1	0.32		1
14	CIRCLEVILLE	HARRISON	138.00	138.00	2	14.00		1
15	8014 CIRCLEVILLE	HARRISON	138.00	138.00	3	1.00		1
16	LSII	MARION	138.00	138.00	1	2.17		1
17	8015 LSII	MARION	138.00	138.00	3	3.00		1
18	8016 MARION	CANAL	138.00	138.00	4	4.00		1
19	8017 ST CLAIR	CLINTON	138.00	138.00	4	4.00		1
20	HARRISON	MARION	138.00	138.00	2	7.00		1
21	8018 HARRISON	MARION	138.00	138.00	3		3.00	1
22	8019 BIXBY	GROVES-ASTOR	138.00	138.00	1	13.00		1
23	8020 POSTON	HARRISON	138.00	138.00	2	53.98		1
24	8021 BEATTY	WILSON (EAST)	138.00	138.00	3	7.00	1.00	1
25	BEATTY	WILSON (WEST)	138.00	138.00	3		1.00	2
26	8022 BEATTY	WILSON (WEST)	138.00	138.00	3		9.00	1
27	8023 WAVERLY	SARGENTS	138.00	138.00	2	16.00		1
28	WAVERLY	ADAMS-SEAMAN	138.00	138.00	2	25.00		1
29	8024 WAVERLY	ADAMS-SEAMAN	138.00	138.00	2	11.00		1
30	CIRCLEVILLE	SCIPPO	138.00	138.00	2	2.00		1
31	8025 CIRCLEVILLE	SCIPPO	138.00	138.00	1	1.00		1
32	POSTON	LICK	138.00	138.00	1			1
33	8026 POSTON	LICK	138.00	138.00	3	35.00		1
34								
35								
36					TOTAL	7,610.95	160.65	617

Name of Respondent Ohio 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

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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	WAVERLY	LICK	138.00	138.00	1			1
2	WAVERLY	LICK	138.00	138.00	2	16.00		1
3	8027 WAVERLY	LICK	138.00	138.00	3	11.00		1
4	MORSE	GENOA-KARL	138.00	138.00	3	4.00		1
5	8028 MORSE	GENOA-KARL	138.00	138.00	1	5.00		1
6	MORSE	GENOA-KARL	138.00	138.00	2	2.00		1
7	8029 OSU	HESS	138.00	138.00	4	1.00		1
8	8030 WILSON	FIFTH-HESS	138.00	138.00	3	3.00		1
9	WILSON	FIFTH-HESS	138.00	138.00	4	2.00		1
10	WILSON	ROBERTS	138.00	138.00	3	5.00		1
11	8031 WILSON	ROBERTS	138.00	138.00	1			1
12	WILSON	ROBERTS	138.00	138.00	1	1.00		2
13	BIXBY	BUCKEYE STEEL	138.00	138.00	3	3.00	1.00	1
14	BIXBY	BUCKEYE STEEL	138.00	138.00	2	2.00		1
15	8032 BIXBY	BUCKEYE STEEL	138.00	138.00	1	1.17		1
16	8033 GAY	VINE	138.00	138.00	4	2.00		1
17	EAST BROAD	GAHANNA	138.00	138.00	1	0.03	1.03	1
18	8034 EAST BROAD	GAHANNA	138.00	138.00	2	1.00		1
19	EAST BROAD	GAHANNA	138.00	138.00	2	3.00		1
20	8035 HYATT	SAWMILL	138.00	138.00	1			1
21	HYATT	SAWMILL	138.00	138.00	2	5.00		1
22	8036 GAHANNA	MORSE	138.00	138.00	2	5.00		1
23	GAHANNA	MORSE	138.00	138.00	2			1
24	CORRIDOR	MORSE-BLENDON	138.00	138.00	3		7.00	1
25	8037 CORRIDOR	MORSE-BLENDON	138.00	138.00	1	1.00		2
26	8038 CORRIDOR	MORSE	138.00	138.00	3	7.00		1
27	8039 KIRK	EAST BROAD	138.00	138.00	3	10.00		1
28	8040 KIRK	EAST BROAD	138.00	138.00	3		10.00	1
29	8041 CANAL	MOUND	138.00	138.00	4	2.00		1
30	8043 CONESVILLE	TRENT	138.00	138.00	3	52.00		1
31	CONESVILLE	TRENT	138.00	138.00	1			1
32	TRENT	DELAWARE	138.00	138.00	3	13.00		1
33	8044 TRENT	DELAWARE	138.00	138.00	1			1
34	8046 ST. CLAIR	MIFFLIN STELZER	138.00	138.00	1	7.00		1
35								
36					TOTAL	7,610.95	160.65	617

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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	KENNY	KARL	138.00	138.00	3	1.00		1
2	KENNY	KARL	138.00	138.00	3	3.00		1
3	8047 KENNY	KARL	138.00	138.00	4	3.00		1
4	MORSE	CLINTON	138.00	138.00	3		5.00	1
5	MORSE	CLINTON	138.00	138.00	3		3.00	1
6	8048 MORSE	HUNTLEY-CLINTON	138.00	138.00	3	3.00		1
7	BIXBY	GROVES	138.00	138.00	3	3.00		2
8	BIXBY	GROVES	138.00	138.00	1	1.00		2
9	BIXBY	GROVES	138.00	138.00	3			1
10	8049 BIXBY	GROVES	138.00	138.00	1			1
11	POSTON	STROUDS	138.00	138.00	1			1
12	8051 POSTON	STROUDS	138.00	138.00	2	7.00		1
13	8052 HYATT	DELAWARE	138.00	138.00	2	4.00		1
14	8053 BEATTY	CANAL	138.00	138.00	1	11.34	2.00	1
15	8055 CONESVILLE	OHIO CENTRAL	138.00	138.00	2	12.00		1
16	8056 EAST BROAD	ASTOR	138.00	138.00	1	3.00		1
17	8057 HARRISON	BEATTY	138.00	138.00	1,3	8.57	0.12	1
18	8058 HARRISON	S CENTRAL REA	138.00	138.00	1			1
19	8060 BEATTY	MCCOMB	138.00	138.00	1	2.00	3.00	1
20	MORSE	STELZER	138.00	138.00	4	2.00		1
21	8061 MORSE	STELZER	138.00	138.00	1	2.00		1
22	8062 HUNTLEY	LINWORTH	138.00	138.00	1	3.23	1.00	1
23	8065 HYATT	GENOA	138.00	138.00	1	5.00	9.00	1
24	BUCKEYE STEEL	GAY	138.00	138.00	1	3.00		1
25	8066 BUCKEYE STEEL	GAY	138.00	138.00	4	1.00		1
26	POSTON	ELLIOT-DEXTER	138.00	138.00	1			1
27	8067 POSTON	ELLIOT-DEXTER	138.00	138.00	2	7.00		1
28	8068 HYATT	HUNTLEY	138.00	138.00	1	12.00		1
29	LICK	ADDISON	138.00	138.00	2	29.00		1
30	8069 LICK	ADDISON	138.00	138.00	1			1
31	SCIPPO	SCIOTO TRAIL - DUPONT	138.00	138.00	1	1.00		1
32	SCIPPO	SCIOTO TRAIL - DUPONT	138.00	138.00	2		1.00	1
33	8070 SCIPPO	SCIOTO TRAIL-DUPONT	138.00	138.00	2	1.00		1
34								
35								
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	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	DELANO	SCIOTO TRAIL	138.00	138.00	2	11.00		1
2	8071 DELANO	SCIOTO TRAIL	138.00	138.00	1	1.00		1
3	8071 DELANO	SCIOTO TRAIL	138.00	138.00	2	0.31		1
4	SAWMILL	BETHEL	138.00	138.00	1			1
5	8072 SAWMILL	BETHEL	138.00	138.00	3	5.00		1
6	8074 SCIPPO	HARGUS	138.00	138.00	1	1.00		1
7	8075 MOUND	ST. CLAIR	138.00	138.00	4	2.00		1
8	WAVERLY	MULBERRY ROSS	138.00	138.00	1	2.00		1
9	8077 WAVERLY	MULBERRY ROSS	138.00	138.00	1	2.06		1
10	8078 MCCOMB	SULLIVANT-GAY	138.00	138.00		8.00		2
11	MULBERRY	ROSS	138.00	138.00	1		2.00	1
12	MULBERRY	ROSS	138.00	138.00	2	3.00		1
13	8079 MULBERRY	ROSS	138.00	138.00	1	1.00		1
14	8080 EAST BROAD	BEXLEY	138.00	138.00	1	6.00		1
15	EAST BROAD	BEXLEY	138.00	138.00	2			1
16	8081 HYATT	ROSS	138.00	138.00	1	1.00		1
17	8082 CORRIDOR	GENOA	138.00	138.00	1			1
18	8083 CORRIDOR	GAHANNA	138.00	138.00	1	1.00		1
19	KIRK	W. MILLERSPORT	138.00	138.00	3		8.00	1
20	KIRK	W. MILLERSPORT	138.00	138.00	3			1
21	CONESVILLE	KIRK	138.00	138.00	2			1
22	CONESVILLE	KIRK	138.00	138.00	3	38.00		2
23	8086 CONESVILLE	KIRK	138.00	138.00	3	8.00		1
24	8088 HESS	VINE	138.00	138.00	4	2.00		1
25	8092 VINE	CITY OF COLUMBUS EAST	138.00	138.00	1	1.28		1
26	POSTON	W. LANCASTER	138.00	138.00	2	12.00		1
27	POSTON	W. LANCASTER	138.00	138.00	1			1
28	8096 POSTON	W. LANCASTER	138.00	138.00	2	23.00		1
29	8098 VINE	CITY OF COLUMBUS WEST	138.00	138.00	1	1.00		1
30	ST. CLAIR	VINE	138.00	138.00	1	1.00		1
31	8099 ST. CLAIR	VINE	138.00	138.00	4	1.00		1
32	8102 CLINTON	OSU	138.00	138.00	4	4.00		1
33	8105 DAVIDSON RD	ROBERTS-BETHEL	138.00	138.00	1			2
34	8129 OSU	HESS	138.00	138.00	4	1.00		1
35	8712 SCIPPO	EAST SCIPPO	138.00	138.00				
36					TOTAL	7,610.95	160.65	617

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Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

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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 (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	8788 FISHER 138KV		138.00	138.00	3	0.42		1
2	C792 CLAYBURNE	KENWORTH	138.00	138.00	1	0.32		1
3	C793 DELANO	KENWORTH	138.00	138.00	1	0.31		1
4	C794 BOLTON EXTENSION		138.00	138.00				
5	COMMONLY OWNED: (F)							
6	C633A BIXBY	POINT N	345.00	345.00	3	14.81		1
7	C633B KIRK	CORRIDOR	345.00	345.00	2	18.38		1
8	TRANSMISSION LINES	LESS THAN 132 KV				607.09	22.50	
9								
10	EXPENSES 765KV LINES							
11	EXPENSES 345KV LINES							
12	EXPENSES 138KV LINES							
13	EXPENSES <132KV LINES							
14								
15								
16								
17								
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	7,610.95	160.65	617

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
954 ACSR	1,349,451	9,045,631	10,395,082					2
954 ACSR								3
954 ACSR	8,552,412	47,088,111	55,640,523					4
954 ACSR								5
1351.5 AC	112,858	1,885,346	1,998,204					6
1351.5 AC	6,337,173	30,096,661	36,433,834					7
1351.5 AC		314,184	314,184					8
1351.5 AC	471,961	1,245,089	1,717,050					9
1351.5 AC	6,908,385	48,233,192	55,141,577					10
1351.5 AC								11
1351.5 AC	1,120,972	10,994,722	12,115,694					12
1351.5 AC	555,058	4,046,333	4,601,391					13
1275 ACSR	73,162	7,507,317	7,580,479					14
2303 ACAR	835,696	7,885,454	8,721,150					15
2303 ACAR								16
1275 ACSR	570,628	9,414,121	9,984,749					17
2303 ACAR								18
1275 ACSR	398,655	2,572,059	2,970,714					19
1414 ACSR	569,553	9,681,540	10,251,093					20
1414 ACSR	324	15,980	16,304					21
1414 ACSR								22
954 ACSR	600,262	4,448,569	5,048,831					23
954 ACSR								24
954 ACSR	216,361	608,479	824,840					25
954 ACSR								26
954 ACSR								27
1414 ACSR	234,856	3,199,207	3,434,063					28
954 ACSR								29
1414 ACSR	374	30,950	31,324					30
1414 ACSR								31
954 ACSR	1,366,276	11,437,901	12,804,177					32
954 ACSR								33
954 ACSR	1,009,385	3,857,729	4,867,114					34
954 ACSR								35
	95,388,388	738,250,834	833,639,222	180,584	12,921,806		13,102,390	36

Name of Respondent Ohio 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

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)
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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.
954 ACSR	391,441	3,342,849	3,734,290					1
954 ACSR	12,388	475,023	487,411					2
954 ACSR	14,027	188,850	202,877					3
1414 ACSR	478,155	2,368,771	2,846,926					4
954 ACSR	415,420	1,876,114	2,291,534					5
954 ACSR								6
954 ACSR	940	225,938	226,878					7
1275 ACSR	102,208	1,124,942	1,227,150					8
2303 ACAR	168,828	1,016,681	1,185,509					9
954 ACSR	457,056	4,364,051	4,821,107					10
954 ACSR		13,499	13,499					11
								12
397.5 ACS	117,254	770,710	887,964					13
397.5 ACS								14
397.5 ACS	18,658	81,441	100,099					15
397.5 ACS								16
556.5 ACS	372,490	1,715,156	2,087,646					17
636 ACSR								18
556.5 ACS	6,248	7,833	14,081					19
556.5 ACS	280,472	1,814,082	2,094,554					20
556.5 ACS								21
336.4 ACS	54,900	408,770	463,670					22
477 ACSR								23
556.5 ACS								24
397.5 ACS	97,721	1,607,351	1,705,072					25
397.5 ACS	2,514	19,200	21,714					26
1033.5 AC								27
397.5 ACS	53,026	521,658	574,684					28
1033.5 AC		369,312	369,312					29
1033.5 AC	98,376	1,339,794	1,438,170					30
477 ACSR	129,031	2,009,240	2,138,271					31
477 ACSR								32
6X477 ACS								33
397.5 ACS		6,970	6,970					34
397.5 ACS	7,006	128,966	135,972					35
	95,388,388	738,250,834	833,639,222	180,584	12,921,806		13,102,390	36

TRANSMISSION LINE STATISTICS (Continued)

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397.5 ACS	84,508	1,272,740	1,357,248					1
397.5 ACS								2
477 ACSR	101,414	1,693,666	1,795,080					3
477 ACSR								4
477 ACSR	47,320	1,099,302	1,146,622					5
397.5 ACS	81,464	762,189	843,653					6
397.5 ACS								7
397.5 ACS	58,821	336,356	395,177					8
477 ACSR	59,245	600,879	660,124					9
477 ACSR								10
397.5 ACS	83,697	734,371	818,068					11
397.5 ACS								12
795 ACSR								13
397.5 ACS	20,086	226,058	246,144					14
556.5 ACS	72,502	940,770	1,013,272					15
636 ACSR	47,622	847,873	895,495					16
556.5 ACS	40,221	874,550	914,771					17
397.5 ACS	149,175	1,311,226	1,460,401					18
397.5 ACS								19
397.5 ACS								20
556.5 ACS	189,074	1,738,272	1,927,346					21
556.5 ACS								22
477 ACSR	315,468	2,916,074	3,231,542					23
336.4 ACS	108,533	1,624,231	1,732,764					24
477 ACSR								25
397.5 ACS	68,327	1,078,941	1,147,268					26
397.5 ACS								27
336.4 ACS	44,469	339,268	383,737					28
4/0 CU.	29,289	629,826	659,115					29
795 ACSR								30
556.5 ACS	279,319	869,029	1,148,348					31
556.5 ACS								32
556.5 ACS								33
1033.5 AC		32,552	32,552					34
								35
	95,388,388	738,250,834	833,639,222	180,584	12,921,806		13,102,390	36

TRANSMISSION LINE STATISTICS (Continued)

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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 ACS	310,450	478,693	789,143					1
795 ACSR								2
556.5 ACS		130,650	130,650					3
477 ACSR	27,518	480,847	508,365					4
200 CU	351,260	3,064,707	3,415,967					5
556.5 ACS	91,838	203,346	295,184					6
556.5 ACS								7
219.9 ACS	36,090	70,490	106,580					8
556.5 ACS								9
795 ACSR	14,809	219,973	234,782					10
636 ACSR	26,598	814,472	841,070					11
1780 ACSR	22,461	287,538	309,999					12
336.4 ACS	30,676	579,360	610,036					13
397.5 ACS	5,172	44,416	49,588					14
795 ACSR	30,216	315,247	345,463					15
556.5 ACS	23,575	252,728	276,303					16
556.5 ACS								17
397.5 ACS		6,879	6,879					18
397.5 ACS								19
556.5 ACS	11,019	105,822	116,841					20
556.5 ACS								21
477 ACSR	79,161	3,729,589	3,808,750					22
477 ACSR								23
477 ACSR								24
219.9 ACS	11,916	455,463	467,379					25
397.5 ACS	15,784	548,597	564,381					26
500 CU.		2,786	2,786					27
219.9 ACS		2,576	2,576					28
219.9 ACS	751	40,348	41,099					29
219.9 ACS	522	85,069	85,591					30
556.5 ACS								31
397.5 ACS	114,989	996,378	1,111,367					32
556.5 ACS								33
1033.5 AC		5,723	5,723					34
1033.5 AC		7,048	7,048					35
	95,388,388	738,250,834	833,639,222	180,584	12,921,806		13,102,390	36

Name of Respondent Ohio 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

TRANSMISSION LINE STATISTICS (Continued)

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336.4 ACS	16,999	106,597	123,596					1
556.5 ACS	210,656	423,220	633,876					2
556.5 ACS								3
556.5 ACS	139,504	477,239	616,743					4
556.5 ACS								5
4/0 ACSR	13,905	214,660	228,565					6
477 ACSR	206,654	1,424,062	1,630,716					7
556.5 ACS	98,865	848,748	947,613					8
636 ACSR								9
1033.5 AC	1,686	143,489	145,175					10
556.5 ACS	99,850	397,053	496,903					11
556.5 ACS	6,084	36,352	42,436					12
556.5 ACS	4,128	25,660	29,788					13
556.5 ACS	1,423	35,982	37,405					14
397.5 ACS	7,029	317,785	324,814					15
397.5 ACS								16
4/0 ACSR	14,193	131,571	145,764					17
1033.5 AC	1,475	136,392	137,867					18
1033.5 AC	120,715	201,698	322,413					19
397.5 ACS								20
556.5 ACS	115,909	300,858	416,767					21
556.5 ACS	40,871	154,440	195,311					22
954 ACSR								23
556.5 ACS	229,027	824,095	1,053,122					24
556.5 ACS								25
1033.5 AC	3,597	210,425	214,022					26
1033.5 AC								27
1033.5 AC	118,635	583,357	701,992					28
636 ACSR								29
636 ACSR	190,216	483,917	674,133					30
397.5 ACS		69,158	69,158					31
1033.5 AC	378	338,249	338,627					32
1780 ACSR	2,610	344,396	347,006					33
556.5 ACS								34
556.5 ACS	79,051	350,039	429,090					35
	95,388,388	738,250,834	833,639,222	180,584	12,921,806		13,102,390	36

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336.4 ACS	7,806	88,199	96,005					1
556.5 ACS	84,321	242,878	327,199					2
556.5 ACS								3
636 ACSR	106,467	413,003	519,470					4
636 ACSR	339,163	1,218,004	1,557,167					5
1033.5 AC	16,563	389,064	405,627					6
1033.5 AC								7
556.5 ACS	35,642	357,967	393,609					8
636 ACSR	21,763	355,008	376,771					9
795 ACSR		25,021	25,021					10
795 ACSR		24,681	24,681					11
795 ACSR	57,799	498,842	556,641					12
1590 ACSR	155,698	1,224,034	1,379,732					13
4/0 CU.								14
556.5 ACS								15
556.5 ACS								16
556.5 ACS		55,737	55,737					17
556.5 ACS		19,301	19,301					18
556.6 ACS		19,770	19,770					19
795 ACSR	518,302	1,112,327	1,630,629					20
795 ACSR								21
795 ACSR								22
1033.5 AC	171,905	1,367,574	1,539,479					23
954 ACSR								24
556.5 ACS		4,938	4,938					25
556.5 ACS	147,936	439,211	587,147					26
795 ACSR	227,558	981,563	1,209,121					27
795 ACSR								28
556.5 ACS	868	10,088	10,956					29
636 ACSR	96,160	583,109	679,269					30
556.5 ACS	234,776	833,416	1,068,192					31
556.5 ACS								32
795 ACSR								33
795 ACSR	123,110	574,358	697,468					34
795 ACSR								35
	95,388,388	738,250,834	833,639,222	180,584	12,921,806		13,102,390	36

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795 ACSR	171,730	742,532	914,262					1
795 ACSR								2
336.4 ACS	7,295	6,963	14,258					3
795 ACSR	263,763	1,589,142	1,852,905					4
795 ACSR								5
556.5 ACS	16,142	474,178	490,320					6
636 ACSR								7
556.5 ACS		5,580	5,580					8
556.5 ACS		6,304	6,304					9
795 ACSR	46,016	264,016	310,032					10
795 ACSR								11
	232	9,417	9,649					12
1033.5 AC	412	553,053	553,465					13
556.5 ACS	35,977	243,930	279,907					14
556.5 ACS	19,114	181,347	200,461					15
556.5 ACS	138,868	445,812	584,680					16
795 ACSR								17
556.5 ACS	23,751	555,222	578,973					18
795 ACSR								19
336.4 ACS		20,442	20,442					20
1033.5 AC		7,504	7,504					21
795 ACSR	327,915	3,936,041	4,263,956					22
795 ACSR								23
556.5 ACS	67,989	270,925	338,914					24
556.5 ACS	1	16,202	16,203					25
556.5 ACS	2	20,499	20,501					26
795 ACSR	108,502	105,267	213,769					27
556.5 ACS	35,321	45,208	80,529					28
795 ACSR	21,856	102,801	124,657					29
795 ACSR								30
1033.5 AC	207,578	631,713	839,291					31
1033.5 AC	189,408	524,861	714,269					32
1033.5 AC		12,561	12,561					33
1033.5 AC		6,432	6,432					34
556.5 ACS	1,299	23,155	24,454					35
	95,388,388	738,250,834	833,639,222	180,584	12,921,806		13,102,390	36

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	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
795 ACSR	28,216	98,324	126,540					1
1033.5 AC	2,527	47,088	49,615					2
795 ACSR	481,243	1,382,999	1,864,242					3
795 ACSR	299,605	283,917	583,522					4
795 ACSR	92,664	690,478	783,142					5
556.5 ACS	27,304	249,067	276,371					6
795 ACSR	24,583	397,019	421,602					7
795 ACSR								8
795 ACSR	86,454	1,173,162	1,259,616					9
795 ACSR								10
795 ACSR								11
795 ACSR	130,564	357,139	487,703					12
795 ACSR	212,391	1,004,078	1,216,469					13
795 ACSR		12,090	12,090					14
795 ACSR	123,243	279,035	402,278					15
636 ACSR		15,828	15,828					16
1033.5 AC	8,058	109,450	117,508					17
1033.5 AC	24,315	121,459	145,774					18
1780 ACSR		43,415	43,415					19
795 ACSR	30,533	162,383	192,916					20
556.5 ACS	9,488	103,743	113,231					21
1590 ACSR		13,046	13,046					22
556.5 ACS	974	41,700	42,674					23
556.5 ACS	18,223	32,856	51,079					24
795 ACSR	8	40,513	40,521					25
556.5 ACS		33,801	33,801					26
336.4 ACS								27
336.4 ACS	5,181	96,269	101,450					28
336.4 ACS	22,978	90,260	113,238					29
	4,300		4,300					30
556.5 ACS	8,496	92,336	100,832					31
336.4 ACS	940	22,202	23,142					32
336.4 ACS	68,548	130,886	199,434					33
1033.5 AC	11,603	84,918	96,521					34
795 ACSR	2,599	176,804	179,403					35
	95,388,388	738,250,834	833,639,222	180,584	12,921,806		13,102,390	36

Name of Respondent Ohio 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

TRANSMISSION LINE STATISTICS (Continued)

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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)	
1033.5 AC	137,311	591,797	729,108					1
1033.5 AC		163,120	163,120					2
336.4 ACS	1,249	218,178	219,427					3
556.5 ACS	53,089	209,764	262,853					4
795 ACSR	13,901	209,058	222,959					5
795 ACSR								6
1033.5 AC	67,168	102,244	169,412					7
1033.5 AC	1,218	118,525	119,743					8
336.4 ACS								9
1033.5 AC	3,617	45,851	49,468					10
1033.5 AC	10,877	59,075	69,952					11
336.4 ACS								12
556.5 ACS		12,614	12,614					13
795 ACSR	481,254	2,956,454	3,437,708					14
336.4 ACS	512	37,478	37,990					15
795 ACSR	6,744	75,116	81,860					16
1033.5 AC	144,421	1,714,306	1,858,727					17
1033.5 AC		2,032,646	2,032,646					18
556.5 ACS	1,275	62,153	63,428					19
336.4 ACS		375,238	375,238					20
556.5 ACS	135	230,743	230,878					21
336.4 ACS		372,700	372,700					22
	9,000	96,880	105,880					23
556.5 ACS	217,676	532,226	749,902					24
556.5 ACS		7,549	7,549					25
4/0 ACSR	-1	-41,451	-41,452					26
397.5 ACS		34,918	34,918					27
556.5 ACS		225,220	225,220					28
556.5 ACS		48,557	48,557					29
397.5 ACS								30
795 ACSR		65	65					31
	15,452,247	166,092,312	181,544,559					32
								33
								34
								35
	95,388,388	738,250,834	833,639,222	180,584	12,921,806		13,102,390	36

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								1
								2
2-954 ACSR								3
2-954 ACSR	1,194,611	3,268,355	4,462,966					4
2-954 ACSR	480,308	5,228,162	5,708,470					5
2-954 ACSR	70,173	4,665,050	4,735,223					6
2-954 ACSR								7
2-954 ACSR								8
2-954 ACSR	835,964	1,916,457	2,752,421					9
2-954 ACSR	1,432,452	4,815,660	6,248,112					10
2-954 ACSR	679,010	4,014,617	4,693,627					11
636 ACSR 26/7		68,482	68,482					12
636 ACSR 26/7		67,644	67,644					13
2000 CU KCM		7,120,559	7,120,559					14
636 ACSR 26/7	254,401	1,251,386	1,505,787					15
636 ACSR 26/7	21,083	716,838	737,921					16
1033.5 KCM	1,297,075	10,611,994	11,909,069					17
1033.5 KCM		1,112,156	1,112,156					18
2000 kcm CU		9,807	9,807					19
								20
954 ACSR 45/7	49,381	970,051	1,019,432					21
954 ACSR 45/7	155,934	1,747,823	1,903,757					22
954 ACSR 45/7	69,245	1,415,282	1,484,527					23
336.4 ACSR 26/7	12,018	75,769	87,787					24
336.4&954 ACSR	62,117	381,813	443,930					25
556.5 ACSR 26/7	149,512	406,453	555,965					26
954 ACSR 45/7	29,932	225,730	255,662					27
954 ACSR 45/7	98,855	1,046,776	1,145,631					28
954 ACSR 45/7	2,143	1,024,374	1,026,517					29
								30
1414 ACSR	14,534	49,229	63,763					31
2-1024 ACAR	341,949	829,458	1,171,407					32
2-1024 ACAR	407,288	1,357,428	1,764,716					33
2-983 ACAR	224,274	1,376,209	1,600,483					34
2-1024 ACAR	457,134	2,262,033	2,719,167					35
	95,388,388	738,250,834	833,639,222	180,584	12,921,806		13,102,390	36

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2-983 ACAR	110,255	1,559,205	1,669,460					1
2-1024 ACAR								2
2-1024 ACAR	380,541	1,547,728	1,928,269					3
2-954 ACSR	262,436	1,445,792	1,708,228					4
2-954 ACSR	292,501	1,255,302	1,547,803					5
		1,160,653	1,160,653					6
2-983 ACAR								7
2-983 ACAR								8
2-983 ACAR	106,814	569,305	676,119					9
								10
2-954 ACSR	238,833	747,276	986,109					11
2-954 ACSR								12
2-954 ACSR	679,660	2,141,019	2,820,679					13
2-954 ACSR								14
2-954 ACSR	360,944	2,120,084	2,481,028					15
2-954 ACSR								16
2-954 ACSR	213,385	563,492	776,877					17
								18
2-954 ACSR	1,514,424	5,947,769	7,462,193					19
								20
2-954 ACSR								21
2-954 ACSR								22
2-954 ACSR	613,989	2,097,710	2,711,699					23
								24
2-954 ACSR								25
2-954 ACSR	46,141	3,333,699	3,379,840					26
2-954 ACSR	261,902	3,054,661	3,316,563					27
2-954 ACSR	232,956	2,023,424	2,256,380					28
2-954 ACSR	153,013	531,322	684,335					29
636 ACSR								30
636 ACSR	115,938	877,798	993,736					31
2500 ALUM	15,618	2,565,158	2,580,776					32
0	1,623		1,623					33
636 ACSR								34
636 AA	24,771	294,624	319,395					35
	95,388,388	738,250,834	833,639,222	180,584	12,921,806		13,102,390	36

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636 ACSR		5,881	5,881					1
636 ACSR	259,495	446,742	706,237					2
636 AA	81,899	623,525	705,424					3
636 ACSR								4
636 ACSR								5
636 ACSR	50,964	3,079,914	3,130,878					6
4/O CWC								7
954 ACSR								8
636 ACSR	65,673	1,352,070	1,417,743					9
636 ACSR								10
636 ACSR	119,332	1,790,435	1,909,767					11
336.4 ACSR	23,022	397,715	420,737					12
556.5 ACSR 18/1								13
336.4 ACSR								14
636 ACSR	136,682	1,370,995	1,507,677					15
636 ACSR								16
636 ACSR	236,419	1,834,732	2,071,151					17
600 CU PIPT		774,047	774,047					18
600 CU PIPT	2	637,129	637,131					19
636 ACSR								20
636 ACSR	48,503	553,806	602,309					21
636 AA	609,590	1,716,584	2,326,174					22
636 ACSR	356,228	2,529,395	2,885,623					23
636 ACSR	93,917	544,710	638,627					24
636 ACSR								25
636 ACSR	137,166	674,000	811,166					26
636 ACSR	93,908	1,635,439	1,729,347					27
336.4 ACSR								28
636 ACSR	234,782	2,585,690	2,820,472					29
336.4 ACSR								30
636 ACSR	22,166	720,728	742,894					31
636 ACSR								32
636 ACSR	314,712	1,731,400	2,046,112					33
								34
								35
	95,388,388	738,250,834	833,639,222	180,584	12,921,806		13,102,390	36

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636 ACSR								1
636 ACSR								2
636 ACSR	959,032	4,594,785	5,553,817					3
1272 ACSR								4
636 ACSR	185,489	901,459	1,086,948					5
600 CU PIPT								6
636 ACSR	69,573	2,041,637	2,111,210					7
600 CU PIPT	91,627	1,031,476	1,123,103					8
636 ACSR								9
636 ACSR								10
636 ACSR	497,262	2,417,958	2,915,220					11
636 ACSR								12
636 ACSR								13
636 AA								14
1250 CU PIPT	11,703	909,031	920,734					15
954 ACSR	64,446	564,718	629,164					16
636 AA								17
336.4 ACSR	79,765	496,425	576,190					18
636 ACSR								19
636 ACSR	90,857	729,292	820,149					20
336.4 ACSR								21
636 ACSR	19,285	3,880,729	3,900,014					22
1272 ACSR								23
1272 ACSR								24
1272 ACSR		486,012	486,012					25
1272 ACSR	330,140	415,091	745,231					26
1272 ACSR	291,072	698,177	989,249					27
600 CU PIPT	786	265,320	266,106					28
1272 ACSR	18,282	1,214,748	1,233,030					29
1272 ACSR	655,122	2,600,886	3,256,008					30
1272 ACSR								31
1272 ACSR								32
1272 ACSR	320,725	942,172	1,262,897					33
636 AA	68,610	1,094,147	1,162,757					34
								35
	95,388,388	738,250,834	833,639,222	180,584	12,921,806		13,102,390	36

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1272 ACSR								1
336.4 ACSR								2
2500 ALUM	14,717	2,190,616	2,205,333					3
1272 ACSR								4
636 ACSR								5
636 AA	12,669	306,092	318,761					6
636 ACSR								7
636 ACSR								8
1272 ACSR								9
336.4 ACSR	495,915	652,871	1,148,786					10
1272 KCM								11
636 ACSR	64,779	664,762	729,541					12
636 ACSR	39,429	421,208	460,637					13
636 AA	112,487	1,452,614	1,565,101					14
636 ACSR	180,778	1,421,676	1,602,454					15
636 AA	4,790	298,258	303,048					16
336.4 ACSR	75,476	81,713	157,189					17
636 AA		20,701	20,701					18
636 AA	155,011	881,264	1,036,275					19
2500 CU PIPT								20
636 AA	17,716	1,344,121	1,361,837					21
636 ACSR	27,349	897,921	925,270					22
636 ACSR	37,272	1,452,760	1,490,032					23
636 AA								24
1259 CU PIPT		818,625	818,625					25
1272 KCM								26
636 ACSR	224,722	1,019,093	1,243,815					27
636 ACSR	288,209	4,540,683	4,828,892					28
336.4 ACSR								29
336.4 ACSR	72,907	2,060,328	2,133,235					30
636 ACSR								31
636 ACSR								32
336 ACSR	95,298	310,036	405,334					33
								34
								35
	95,388,388	738,250,834	833,639,222	180,584	12,921,806		13,102,390	36

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336.4 ACSR								1
636 ACSR	111,897	643,413	755,310					2
556.5 ACSR 18.1								3
636 ACSR								4
636 ACSR	66,964	335,716	402,680					5
636 ACSR	36,779	222,684	259,463					6
600 CU PIPT	9,105	1,200,257	1,209,362					7
636 ACSR								8
636 ACSR	88,501	2,297,251	2,385,752					9
636 ACSR	472,319	5,075,671	5,547,990					10
636 ACSR								11
636 ACSR								12
636 ACSR	30,427	912,264	942,691					13
954 ACSR	246,919	1,317,661	1,564,580					14
954 ACSR								15
1272 ACSR	157,798	134,946	292,744					16
1272 ACSR		555,336	555,336					17
1272 ACSR	132,616	556,258	688,874					18
1272 ACSR								19
636 ACSR								20
1272 ACSR								21
1272 ACSR								22
1272 ACSR	457,078	2,914,944	3,372,022					23
1250 CU PIPT		1,179,534	1,179,534					24
983.1 ACAR	56,822	1,046,998	1,103,820					25
636 ACSR								26
636 ACSR								27
336 ACSR	35,117	1,300,110	1,335,227					28
983.1 ACSR	268,205	525,039	793,244					29
954 ACSR								30
2750 CU KCM	544,816	2,932,159	3,476,975					31
600 CU PIPT	174,545	1,186,767	1,361,312					32
636 ACSR		359,788	359,788					33
600 CU PIPT		371,400	371,400					34
636 ACSR		34,138	34,138					35
	95,388,388	738,250,834	833,639,222	180,584	12,921,806		13,102,390	36

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.
	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
636 ACSR	31,625	483,466	515,091					1
565.5 ACSR 18/1		1,555	1,555					2
556.5 ACSR 18/1		2,421	2,421					3
	39,431		39,431					4
								5
2-954 ACRS	414,014	746,926	1,160,940					6
2-954 ACRS	495,504	976,206	1,471,710					7
	7,268,490	61,491,031	68,759,521					8
								9
				11,773	842,455		854,228	10
				34,537	2,471,314		2,505,851	11
				62,733	4,488,929		4,551,662	12
				71,541	5,119,108		5,190,649	13
								14
								15
								16
								17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	95,388,388	738,250,834	833,639,222	180,584	12,921,806		13,102,390	36

Schedule Page: 422.9 Line No.: 1 Column: a

422.9 Line 1
On December 31, 2011, AEP affiliates Columbus Southern Power Company and Ohio Power Company were merged into one company, Ohio Power Company.

422.9 Line 30
TRANSMISSION LINE STATISTICS:

Transmission Lines are co-owned with Duke Energy, The Dayton Power and Light Company (DP&L) and Respondent (OPCO). Statistics represent total line miles, but dollar amounts represent the Respondent's share only. The co-owners are not associated companies.

Ownership percentages are as follows for the respective footnotes:

Company	Duke Energy	DP&L	OPCO
Footnote:			
(A)	30%	35%	35%
(B)	33-1/3%	33-1/3%	33-1/3%
(C)	16.86%	16.86%	66.28%
(D)	8.43%	8.43%	83.14%
(E)	28%	36%	36%
(F)	17.5%	22.5%	60%

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	LINES ALTERED:						
4	0235 - WEST MILLERSPORT	HEATH	2.90	STEEL		1	1
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							
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31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		2.90			1	1

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	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
									1
									2
									3
1590KCM	ACSR		138		2,843,577	452,268		3,295,845	4
									5
									6
									7
									8
									9
									10
									11
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									35
									36
									37
									38
									39
									40
									41
									42
									43
					2,843,577	452,268		3,295,845	44

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	OHIO POWER COMPANY				
2	ACADEMIA-OH	T	138.00	69.00	13.00
3		T	69.00		
4	ADA-OH	D	69.00	13.09	
5	ANCHOR HOCKING (OP)-OH	D	69.00	12.00	
6		D	69.00	4.00	
7		D	34.50	4.00	
8	ANTWERP-OH	D	69.00	12.47	
9	APPLE CREEK-OH	D	138.00	13.09	
10	ASH AVENUE-OH	D	34.50	13.09	
11	AUGLAIZE-OH	D	69.00	13.09	
12	AVONDALE-OH	D	69.00	12.00	
13	BANNOCK ROAD-OH	D	69.00	13.09	
14	BARNESVILLE-OH	D	69.00	13.09	
15	BEALL AVENUE-OH	D	69.00	13.09	
16		D	69.00	4.00	
17	BEAVER-OH	D	69.00	34.50	12.00
18		D	69.00	12.00	
19	BELDEN VILLAGE-OH	D	138.00	13.09	
20	BERLIN (OP)-OH	D	69.00	34.50	
21		D	69.00	13.09	
22	BERWICK-OH	D	69.00	13.09	
23	BILLIAR-OH	D	69.00	13.09	
24	BLACKJACK ROAD-OH	D	69.00	12.00	
25	BLISS PARK-OH	D	69.00	13.09	
26	BLUFFTON (OP)-OH	D	34.50	13.09	
27		D	34.50		
28	BOLIVAR-OH	D	138.00	36.20	
29	BRIDGEPORT-OH	D	69.00	13.09	
30		D	69.00	4.00	
31	BRIDGEVILLE-OH	D	138.00	13.09	
32	BROOM ROAD-OH	D	69.00	13.09	
33		D	69.00		
34	BUCKLEY ROAD-OH	T	138.00	69.50	13.09
35	BUCYRUS-OH	D	69.00	13.09	
36		D	69.00		
37	BUCYRUS CENTER-OH	T	138.00	69.50	13.09
38		T	69.00	13.09	
39	BYESVILLE-OH	D	69.00	12.00	
40	CADIZ-OH	D	69.00	13.09	

Name of Respondent Ohio 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

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	CALCUTTA-OH	D	69.00	13.09	
2	CALDWELL-OH	T	138.00	34.50	
3		T	138.00	13.09	
4	CALIFORNIA-OH	D	69.00	13.09	
5	CAMBRIDGE-OH	D	34.50	12.00	
6		D	34.50	4.00	
7		D	34.50		
8	CANAL ROAD-OH	T	138.00	69.00	34.50
9		T	69.00	23.00	
10	CANTON CENTRAL-OH	T	345.00	137.50	13.14
11	CARROLLTON-OH	D	138.00	13.09	
12	CENTER STREET-OH	D	69.00	12.00	
13	CENTRAL PORTSMOUTH-OH	T	138.00	69.00	34.50
14		T	69.00	7.20	
15	CHATFIELD-OH	T	138.00	69.50	13.09
16	CHERRY AVENUE-OH	D	69.00	12.00	
17	CLIFTMONT AVENUE-OH	D	69.00	12.00	
18	COLUMBUS GROVE-OH	D	69.00	12.47	
19	CONESVILLE PREPARATION PLANT-OH	D	138.00	13.09	
20	COOPERMILL-OH	D	69.00	13.09	
21		D	69.00	4.00	
22		D	69.00		
23	COSHOCTON-OH	D	69.00	12.00	
24		D	69.00	4.00	
25		D	69.00		
26	CRESTWOOD-OH	D	34.50	13.09	
27	CROOKSVILLE-OH	T	138.00	69.00	12.00
28		T	69.00	13.09	
29		T	69.00	4.00	
30	DELPHOS-OH	D	69.00	13.09	
31	DENNISON-OH	T	69.00	36.20	
32		T	69.00	13.09	
33		T	69.00		
34		T	34.50	4.00	
35	DOGWOOD RIDGE-OH	D	138.00	13.09	
36	DON MARQUIS (OP-CS) (OVEC)-OH	T	765.00	345.00	34.50
37		T	345.00		
38		T	345.00	137.50	13.80
39	DOW CHEMICAL-HANGING ROCK-OH	D	69.00	12.00	
40	DRESDEN-OH	D	69.00	12.00	

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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	DUNKIRK (OP)-OH	T	69.00	36.20	
2		T	69.00	13.09	
3		T	69.00		
4	EAST AMSTERDAM-OH	T	138.00	69.00	12.00
5	EAST BEAVER-OH	T	138.00	69.00	34.50
6	EAST CAMBRIDGE-OH	T	69.00	34.50	
7		T	69.00		
8	EAST CANTON-OH	D	69.00	13.09	
9	EAST FREMONT-OH	D	69.00	13.09	
10		D	69.00	4.36	
11	EAST LANCASTER-OH	D	69.00	12.00	
12		D	69.00		
13	EAST LEIPSIC-OH	T	138.00	69.50	7.20
14		T	138.00		
15		T	69.00	36.20	
16	EAST LIMA-OH	T	345.00	137.50	13.80
17		T	345.00	137.50	13.20
18		T	345.00	137.50	13.14
19		T	138.00	69.50	13.09
20		T	138.00		
21	EAST LIVERPOOL-OH	T	138.00	70.50	13.09
22		T	69.00		
23	EAST LOGAN-OH	D	69.00	12.00	
24		D	69.00		
25	EAST NEWARK-OH	D	69.00	13.09	
26		D	69.00	4.00	
27	EAST OTTAWA-OH	T	69.00	13.09	
28		T	69.00		
29	EAST POINTE-OH	D	138.00	13.09	
30	EAST PROCTORVILLE-OH	D	138.00	34.50	
31	EAST SIDE (LIMA)-OH	D	138.00	36.20	
32		D	34.50	4.33	
33	EAST SPARTA-OH	D	23.00	13.09	
34		D	23.00	12.00	
35		D	23.00		
36	EAST TIFFIN-OH	D	69.00	13.09	
37	EAST UNION-OH	D	69.00	13.09	
38	EAST WILLARD-OH	D	69.00	13.09	
39					
40					

SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	EAST WOOSTER-OH	T	138.00	69.50	13.09
2		T	138.00	24.14	
3		T	138.00	13.09	
4		T	138.00		
5	EAST ZANESVILLE-OH	T	138.00	69.00	13.00
6		T	138.00	69.00	12.00
7		T	138.00		
8	EASTON STREET-OH	D	69.00	13.09	
9	EASTOWN ROAD-OH	D	138.00	13.20	
10		D	138.00	13.09	
11	EIGHTEEN STREET HEIGHTS-OH	D	69.00	13.09	
12		D	69.00	12.00	
13	ELIZABETH STREET-OH	D	34.50	4.36	
14	ETNA-OH	D	69.00	34.50	
15		D	69.00	13.09	
16	FAIRCREST STREET-OH	D	138.00	13.09	
17	FAIRDALE-OH	D	69.00	12.00	
18	FAIRFIELD-OH	D	69.00	4.36	
19	FINDLAY-OH	D	34.50	13.09	
20		D	34.50		
21	FINDLAY CENTER-OH	T	138.00	69.50	35.00
22		T	34.50	13.09	
23		T	34.50		
24	FOREST (OP)-OH	T	69.00	23.99	4.16
25		T	69.00	23.50	
26		T	69.00	13.09	
27		T	69.00		
28	FOSTORIA CENTRAL-OH	T	345.00	137.50	13.80
29	FREDERICKTOWN-OH	D	69.00	13.09	
30	FREMONT (OP)-OH	T	138.00	69.50	13.09
31		T	69.00		
32	FREMONT CENTER-OH	T	138.00	70.50	13.09
33		T	138.00		
34		T	69.00	13.09	
35		T	69.00		
36	GAMBIER-OH	D	69.00	12.00	
37	GAVIN-OH	T	765.00	69.00	
38		T	138.00		
39		T	138.00	69.00	12.00
40		T	69.00	12.00	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	GLENMOOR-OH	D	69.00	12.00	
2	GRANVILLE-OH	D	69.00	13.09	
3		D	69.00	12.00	
4	GREELY-OH	D	69.00	13.09	
5		D	69.00	4.36	
6	GREENLAWN-OH	T	138.00	69.50	13.09
7	GREER-OH	T	69.00	35.00	
8		T	34.50		
9		T	34.50	12.00	
10	HAMMONDSVILLE-OH	T	69.00	23.00	
11		T	69.00		
12	HANGING ROCK-OH	T	765.00		
13		T	138.00	69.00	34.50
14	HARPSTER-OH	T	69.00	35.00	
15	HAVILAND-OH	T	138.00	69.50	13.09
16		T	138.00	13.09	
17	HEATH-OH	T	138.00	69.00	12.00
18		T	138.00	34.50	
19		T	69.00	4.00	
20	HIGHLAND AVENUE-OH	D	69.00	13.09	
21	HIGHLAND TERRACE-OH	D	69.00	13.09	
22	HOCKING-OH	T	138.00	69.00	12.00
23	HOWARD-OH	T	138.00	69.50	11.00
24		T	138.00		
25		T	69.00	13.09	
26		T	69.00		
27	HUGHES STREET-OH	D	69.00	4.36	
28	KALIDA-OH	T	69.00	35.00	
29		T	69.00	13.09	
30		T	69.00		
31	KAMMER 138KV-WV	T	138.00	34.50	
32		T	138.00		
33	KAMMER 345KV-WV	T	345.00	137.50	13.80
34	KAMMER 400 YARD-WV	T	765.00	345.00	34.50
35	KAMMER 765-500KV-WV	T	765.00		
36	KENTON-OH	D	69.00	36.20	
37		D	69.00		
38	LANCASTER-OH	D	69.00	12.00	
39		D	69.00	4.00	
40		D	69.00		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio 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.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	LANCASTER JUNCTION-OH	D	69.00	13.09	
2		D	69.00	12.00	
3	LEESVILLE (OP)-OH	D	69.00	13.09	
4	LEIPSIC-OH	D	69.00	13.09	
5	LINDEN AVENUE-OH	D	69.00	12.00	
6		D	69.00	4.00	
7		D	69.00		
8	LOCK SEVENTEEN-OH	D	69.00	13.00	
9		D	69.00		
10	LOUISVILLE-OH	D	69.00	12.00	
11	MAHONING ROAD-OH	D	69.00	12.00	
12	MALVERN-OH	T	138.00	69.00	12.00
13		T	138.00	23.00	12.00
14		T	23.00	12.00	
15	MARTINS FERRY-OH	D	69.00	12.00	
16	MARTINSBURG ROAD-OH	D	69.00	13.09	
17	MARYSVILLE-OH	T	765.00		
18		T	765.00	345.00	34.50
19		T	765.00	345.00	12.00
20	MAULE ROAD-OH	D	69.00	13.09	
21	MCCOMB (OP)-OH	D	34.50	13.09	
22	MEIGS NO. 1-OH	D	138.00	34.50	
23	MEIGS NO. 2-OH	D	138.00	34.50	
24	MEMORIAL DRIVE-OH	D	69.00	13.09	
25	MILES AVENUE-OH	D	138.00	13.09	
26	MILL STREET-OH	D	69.00	12.00	
27	MILLBROOK PARK-OH	T	138.00	69.00	34.50
28		T	138.00	34.50	11.00
29		T	138.00		
30		T	34.50	12.00	
31	MILLWOOD-OH	D	138.00	13.09	
32	MINERVA-OH	D	69.00	13.09	
33	MINFORD-OH	D	69.00	12.00	
34	MONROE STREET-OH	D	69.00	12.00	
35	MOUNT VERNON (OP)-OH	D	69.00	12.00	
36		D	69.00	4.00	
37	MUSKINGUM RIVER 138KV-OH	T	345.00	141.00	13.20
38		T	345.00	137.50	13.80
39		T	138.00	69.00	13.09
40	NEGLEY-OH	D	138.00	13.09	

Name of Respondent Ohio 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

SUBSTATIONS

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2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	NEW LEXINGTON-OH	D	69.00	13.09	
2		D	69.00		
3	NEW LIBERTY-OH	T	138.00	70.50	36.20
4		T	138.00	34.50	
5		T	138.00	13.09	
6		T	138.00		
7		T	34.50		
8	NEW PHILADELPHIA-OH	D	69.00	36.20	
9		D	69.00		
10	NEWARK-OH	D	69.00	4.36	
11		D	69.00		
12	NEWARK CENTER-OH	T	138.00	69.00	12.00
13	NEWCOMERSTOWN-OH	T	138.00	69.00	12.00
14		T	69.00	34.50	12.00
15		T	69.00		
16	NORTH BALTIMORE-OH	D	34.50	13.09	
17		D	34.50		
18	NORTH BELLVILLE-OH	T	138.00	69.50	13.09
19		T	69.00		
20	NORTH CAMBRIDGE-OH	D	69.00	13.09	
21		D	69.00	4.36	
22	NORTH CANTON-OH	D	69.00	13.09	
23		D	69.00		
24	NORTH COSHOCTON-OH	T	69.00	34.50	12.00
25		T	69.00	12.00	
26		T	69.00		
27	NORTH CROWN CITY-OH	T	138.00	69.00	13.20
28	NORTH DELPHOS-OH	T	138.00	70.50	36.20
29		T	69.00		
30	NORTH END FOSTORIA-OH	D	69.00	13.09	
31	NORTH FINDLAY-OH	T	138.00	69.50	35.00
32		T	138.00	35.00	
33		T	138.00		
34		T	34.50		
35	NORTH FREMONT-OH	D	69.00	13.09	
36	NORTH HEBRON-OH	D	69.00	34.50	
37	NORTH HICKSVILLE-OH	D	69.00	13.09	
38	NORTH LEIPSIC-OH	D	69.00	13.09	
39	NORTH LEXINGTON-OH	D	138.00	13.09	
40	NORTH MUSKINGUM-OH	T	138.00	69.00	12.00

Name of Respondent Ohio 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

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	NORTH NEWARK-OH	T	138.00	69.00	4.00
2		T	138.00	13.09	
3		T	138.00		
4		T	69.00	12.00	
5		T	69.00	4.00	
6		T	69.00		
7	NORTH PORTSMOUTH-OH	T	138.00	69.00	34.50
8	NORTH PROCTORVILLE-OH	T	765.00	138.00	13.80
9	NORTH SPENCERVILLE-OH	D	69.00	13.09	
10	NORTH UPPER SANDUSKY-OH	D	69.00	13.09	
11	NORTH WALDO-OH	T	138.00	69.00	7.20
12		T	69.00	13.09	
13	NORTH WELLSVILLE-OH	D	69.00	12.00	
14		D	69.00		
15	NORTH WILLARD-OH	D	69.00	13.09	
16		D	69.00		
17	NORTH WOODCOCK-OH	T	138.00	69.50	35.50
18		T	34.50		
19	NORTH WOOSTER-OH	D	69.00	12.00	
20	NORTH ZANESVILLE-OH	D	138.00	13.09	
21	NORTHEAST CANTON-OH	T	138.00	69.00	12.00
22		T	69.00		
23	NORTHEAST FINDLAY-OH	T	138.00	36.20	
24	NORTHWEST LIMA-OH	D	138.00	13.09	
25	NORVAL PARK-OH	D	69.00	4.00	
26	OAKLAND-OH	D	69.00	12.00	
27	OAKWOOD ROAD-OH	D	69.00	12.00	
28	OERTELS CORNERS-OH	D	69.00	12.00	
29	OHIO CENTRAL-OH	T	345.00	137.50	13.12
30		T	138.00	70.50	36.20
31		T	138.00	69.00	12.00
32		T	138.00	69.00	4.00
33		T	138.00	13.09	
34		T	69.00	34.50	
35		T	69.00	12.00	
36		T	23.00	12.00	
37		T	23.00	4.00	
38	PACKARD-OH	D	138.00	13.20	
39	PAULDING-OH	D	69.00	13.09	
40		D	69.00		

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1	PEKIN-OH	T	69.00	23.00	
2		T	69.00	13.09	
3		T	69.00		
4	PIEDMONT AVENUE-OH	D	26.00	4.00	
5	PITTSBURGH AVENUE-OH	D	69.00	13.09	
6	PLEASANT STREET-OH	T	69.00	34.50	
7		T	69.00	13.09	
8		T	69.00		
9	PLYMOUTH HEIGHTS-OH	D	69.00	12.00	
10	POWELSON-OH	D	138.00	13.09	
11	PROMWAY-OH	D	138.00	13.09	
12	QUARRY ROAD-OH	D	69.00	12.00	
13	RACINE HYDRO-OH	T	69.00	13.09	
14	RALSTON-OH	D	69.00	12.00	
15	REEDURBAN-OH	T	138.00	69.50	13.09
16		T	138.00	13.09	
17	RIVERVIEW (OP)-OH	D	69.00	13.09	
18		D	69.00	4.36	
19		D	69.00		
20	ROBB AVENUE-OH	D	34.50	4.00	
21	ROCKHILL (OP)-OH	T	138.00	35.00	
22		T	138.00	34.65	11.00
23		T	138.00	13.09	
24		T	34.50		
25	ROSEMOUNT-OH	D	69.00	34.50	
26		D	69.00	13.09	
27	RUTLAND-OH	T	138.00	34.50	
28	SAINT CLAIR AVENUE (OP)-OH	D	69.00	13.09	
29	SAVANNAH AVENUE-OH	D	69.00	22.90	13.09
30	SCHOENBRUNN-OH	D	69.00	12.00	
31	SCHROYER AVENUE-OH	T	69.00	23.00	13.09
32		T	69.00	13.09	
33		T	69.00	4.00	
34		T	69.00		
35	SCIOTO TRAIL (OP)-OH	D	34.50	13.09	
36	SEROCO AVENUE-OH	D	69.00	4.00	
37	SHADYSIDE-OH	D	69.00	13.09	
38	SHARON VALLEY-OH	D	69.00	13.09	
39	SHARP ROAD-OH	T	138.00	69.00	12.00
40		T	69.00		

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1	SHAWNEE ROAD-OH	T	138.00	69.50	35.00
2		T	138.00	13.09	
3	SHREVE-OH	D	69.00	13.09	
4	SOMERTON-OH	T	138.00	69.00	12.00
5	SOUTH BALTIMORE-OH	T	138.00	69.00	4.00
6	SOUTH BELMONT-OH	D	69.00	13.09	
7	SOUTH BERWICK-OH	T	345.00	68.80	13.09
8	SOUTH CADIZ-OH	T	138.00	69.00	12.00
9		T	69.00	12.00	
10		T	69.00		
11	SOUTH CAMBRIDGE-OH	T	69.00	34.50	
12		T	69.00	34.50	12.00
13		T	69.00		
14	SOUTH CANTON 345KV-OH	T	345.00	137.50	35.00
15	SOUTH CANTON 765KV-OH	T	765.00	345.00	34.50
16	SOUTH COSHOCTON-OH	T	138.00	69.00	12.00
17		T	138.00	36.00	7.20
18		T	138.00	13.09	
19		T	69.00	34.50	12.00
20		T	34.50	12.00	
21	SOUTH CUMBERLAND-OH	T	138.00	69.00	34.50
22		T	138.00	25.00	
23	SOUTH DELPHOS-OH	D	69.00	13.09	
24	SOUTH FINDLAY-OH	D	34.50	13.09	
25		D	34.50		
26	SOUTH GRANVILLE-OH	D	69.00	13.09	
27	SOUTH HICKSVILLE-OH	T	138.00	69.50	13.09
28		T	69.00		
29	SOUTH KENTON-OH	T	138.00	69.00	
30		T	2.50		
31	SOUTH LANCASTER-OH	T	138.00	69.00	34.50
32		T	138.00	69.00	12.00
33	SOUTH LUCASVILLE-OH	D	138.00	13.09	
34	SOUTH MARTINS FERRY-OH	D	69.00	13.09	
35	SOUTH MILLERSBURG-OH	T	138.00	35.00	7.20
36		T	34.50		
37	SOUTH NEWARK-OH	D	69.00	12.00	
38					
39					
40					

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1	SOUTH POINT-OH	T	138.00	69.00	34.50
2		T	138.00	34.50	
3		T	138.00		
4		T	34.50	12.00	
5	SOUTH SIDE LIMA-OH	D	34.50	13.09	
6		D	34.50	4.36	
7	SOUTH TIFFIN-OH	T	138.00	69.30	6.90
8	SOUTH TORONTO-OH	T	138.00	69.50	13.09
9	SOUTH VAN WERT-OH	D	69.00	13.09	
10		D	69.00	4.36	
11		D	69.00		
12	SOUTHEAST CANTON-OH	T	345.00	137.50	34.50
13	SOUTHEAST LOGAN-OH	D	69.00	12.00	
14	SOUTHWEST LIMA-OH	T	345.00	138.00	13.80
15		T	345.00	137.50	13.80
16		T	345.00	137.50	13.12
17		T	138.00		
18	ST RITAS HOSP-OH	D	34.50	4.16	
19	STADIUM PARK-OH	D	69.00	13.09	
20		D	69.00	12.00	
21		D	69.00		
22	STANLEY COURT-OH	T	69.00	13.09	
23		T	69.00		
24	STERLING-OH	T	138.00	33.00	
25		T	138.00	33.00	11.00
26		T	34.50		
27	STEUBENVILLE-OH	T	138.00	69.00	12.00
28	STONE STREET-OH	D	69.00	13.09	
29		D	69.00	4.36	
30	STONY HOLLOW-OH	D	69.00	13.09	
31	STRASBURG-OH	D	138.00	36.20	
32	SUGARCREEK TERMINAL-OH	D	138.00	13.09	
33	SUMMERFIELD-OH	T	138.00	69.00	12.00
34	SUMMERHILL-OH	D	69.00	13.09	
35	SUNNYSIDE-OH	T	138.00	23.00	
36		T	138.00	23.00	6.90
37		T	138.00	13.09	
38		T	138.00		
39		T	23.00		
40	SUNSET BOULEVARD-OH	D	69.00	13.09	

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1	SWITZER-OH	T	138.00	69.00	12.00
2	THAYER ROAD-OH	D	138.00	13.09	
3	THIRD STREET-OH	D	69.00	13.09	
4		D	23.00	4.33	
5		D	23.00	4.00	
6	THORNVILLE-OH	D	69.00	13.09	
7	TIDD 138KV-OH	T	138.00	13.09	
8		T	138.00		
9	TIDD 345KV-OH	T	345.00	141.00	13.20
10		T	345.00	137.50	13.80
11		T	138.00	13.80	
12		T	34.50	4.00	
13	TIDD 69KV-OH	T	138.00	69.00	34.50
14		T	69.00	12.00	
15	TIFFIN CENTER-OH	T	138.00	69.50	13.09
16	TIFFIN TAP-OFF-OH	D	69.00	13.09	
17		D	69.00	4.36	
18	TILTONSVILLE-OH	T	138.00	69.00	12.00
19		T	69.00	13.09	
20		T	69.00		
21	TIMKEN-OH	T	138.00	24.14	
22	TIMKEN MERCY-OH	D	69.00	4.00	
23	TORONTO-OH	D	69.00	13.09	
24	TORREY-OH	T	138.00	69.00	12.00
25		T	138.00	23.00	11.00
26		T	138.00		
27		T	69.00	13.09	
28		T	69.00		
29		T	23.00	12.00	
30	TWO RIDGES-OH	D	69.00	12.00	
31	UPPER SANDUSKY-OH	D	69.00	13.09	
32		D	69.00		
33	UTICA (OP)-OH	D	69.00	13.09	
34	VAN WERT-OH	D	69.00	13.09	
35		D	69.00	4.36	
36		D	69.00		
37	WAGENHALS-OH	T	138.00	70.50	13.09
38		T	138.00	69.00	23.00
39		T	138.00	23.50	7.20
40		T	138.00		

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1	WAKEFIELD-OH	T	138.00	13.09	
2	WAYVIEW-OH	T	138.00	69.00	12.00
3		T	138.00	13.09	
4	WEST BELLAIRE-OH	T	345.00	137.50	13.12
5		T	138.00	69.00	12.00
6	WEST CAMBRIDGE-OH	T	138.00	69.00	13.09
7		T	138.00	36.20	
8		T	138.00		
9	WEST CANTON-OH	T	138.00	69.50	13.09
10		T	138.00	36.20	
11		T	138.00	13.09	
12		T	138.00		
13		T	69.00	36.20	
14		T	69.00		
15	WEST COSHOCTON-OH	T	138.00	69.00	13.09
16	WEST DOVER-OH	T	138.00	69.50	13.09
17	WEST END FOSTORIA-OH	T	138.00	69.50	13.09
18		T	138.00		
19		T	69.00	4.36	
20		T	69.00	4.16	
21		T	69.00		
22	WEST GRANVILLE-OH	D	69.00	12.00	
23		D	69.00		
24	WEST HEBRON-OH	T	138.00	69.00	34.50
25		T	34.50	34.50	
26		T	34.50		
27	WEST HICKSVILLE-OH	D	69.00	13.09	
28	WEST LANCASTER-OH	T	138.00	69.00	12.00
29		T	138.00		
30		T	69.00		
31	WEST LIMA-OH	T	138.00	35.00	
32		T	138.00		
33	WEST LOGAN-OH	D	69.00	12.00	
34	WEST LOUISVILLE-OH	D	69.00	12.00	
35		D	69.00		
36	WEST MELROSE-OH	D	34.50	13.09	
37	WEST MILLERSBURG-OH	D	138.00	69.00	34.50
38		D	138.00	36.20	
39	WEST MILLERSPORT-OH	T	345.00	137.50	13.80
40		T	138.00	70.50	13.09

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1	WEST MOULTON-OH	T	138.00	70.50	36.20
2		T	69.00	13.09	
3	WEST MOUNT VERNON-OH	T	138.00	69.00	4.00
4		T	138.00		
5		T	69.00		
6	WEST NEW PHILADELPHIA-OH	T	138.00	69.00	12.00
7		T	138.00	34.50	4.00
8		T	138.00	13.09	
9		T	138.00		
10	WEST TORONTO-OH	D	69.00	13.09	
11	WEST TRINWAY-OH	D	138.00	13.09	
12	WEST VAN WERT-OH	T	69.00	35.00	
13	WEST WOOSTER-OH	D	69.00	12.00	
14		D	69.00		
15	WHIRLPOOL (OP)-OH	D	34.50	13.09	
16	WILLISTON AVENUE-OH	D	69.00	13.09	
17	WINTERSVILLE-OH	D	69.00	12.00	
18	WOODLAWN (OP)-OH	D	138.00	13.09	
19	WOOSTER-OH	T	138.00	69.50	13.09
20		T	138.00	24.14	
21		T	138.00	13.09	
22		T	138.00		
23	ZANESVILLE-OH	T	138.00	69.00	12.00
24		T	138.00	13.09	
25		T	138.00		
26					
27	174 STATIONS UNDER 10 MVA	T/D			
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

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1	COLUMBUS SOUTHERN POWER				
2	ADAMS (CSP)-OH	T	138.00	69.00	13.09
3		T	69.00		
4	ADDISON-OH	T	138.00	69.00	13.00
5		T	69.00	12.00	
6		T	69.00		
7		T	13.20		
8	ADENA-OH	D	69.00	13.09	
9	ASTOR-OH	D	138.00	13.80	13.80
10		D	13.80		
11	BEATTY ROAD-OH	T	345.00	137.50	13.80
12		T	138.00	69.00	13.80
13		T	138.00	69.00	13.00
14		T	138.00	36.20	
15		T	138.00	13.80	
16		T	13.20		
17	BELPRE-OH	D	138.00	13.09	
18	BERKSHIRE-OH	D	138.00	35.40	13.80
19		D	34.50		
20		D	34.50		
21	BERLIN (CSP)-OH	D	69.00	13.00	
22		D	69.00	12.00	
23		D	13.20		
24	BETHEL ROAD-OH	T	138.00	69.50	13.09
25		T	138.00	13.80	13.80
26		T	138.00		
27		T	13.20		
28	BEXLEY-OH	T	138.00	40.00	13.80
29		T	138.00	39.40	13.80
30		T	138.00	13.80	13.80
31		T	46.00		
32		T	13.20		
33					
34					
35					
36					
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38					
39					
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Name of Respondent Ohio 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

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	BIXBY-OH	T	345.00	138.00	35.00
2		T	345.00	138.00	34.50
3		T	138.00	13.80	
4		T	138.00	13.80	13.80
5		T	138.00	13.09	
6		T	69.00	13.80	
7		T	69.00	13.20	
8		T	69.00	13.09	
9		T	69.00	4.36	
10		T	40.00	14.50	
11		T	40.00	13.80	
12		T	34.50	4.00	
13		T	23.00	13.09	
14		T	13.20		
15	BLACKLICK-OH	D	138.00	35.40	13.80
16		D	34.50		
17		D	13.80		
18	BLENDON-OH	D	138.00	35.40	13.80
19		D	138.00	34.50	13.80
20	BRIGGSDALE-OH	D	40.00	13.80	
21		D	13.80		
22	BROOKSIDE (CS)-OH	D	138.00	13.80	
23		D	138.00	13.09	
24	BUCKSKIN-OH	D	69.00	12.00	
25	CAMP SHERMAN-OH	D	69.00	13.09	
26		D	69.00	13.00	
27	CANAL STREET-OH	D	138.00	13.80	13.80
28		D	13.80		
29		D	13.20		
30	CENTERBURG-OH	D	138.00	35.40	13.80
31	CIRCLEVILLE-OH	T	138.00	69.00	13.20
32		T	138.00	13.20	
33		T	138.00		
34		T	69.00		
35		T	13.20		
36	CLARK STREET-OH	D	69.00		
37		D	69.00	12.00	
38		D	69.00		
39	CLINTON-OH	D	138.00	13.80	13.80
40	COLUMBIA(CS)-OH	D	40.00	13.20	

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1	CONESVILLE PLANT-OH	T	345.00	138.00	34.50
2		T	138.00	70.73	13.20
3		T	138.00		
4	COOLVILLE (CS)-OH	D	69.00	13.20	
5	COPELAND-OH	D	69.00	13.20	
6		D	13.20		
7	CORNER-OH	D	138.00	13.09	
8	CORRIDOR-OH	T	345.00	138.00	34.50
9		T	345.00	138.00	13.80
10		T	138.00	34.50	13.80
11		T	138.00		
12	CORWIN-OH	D	138.00	13.09	
13	DAVIDSON (CS)-OH	D	138.00	13.80	
14		D	13.80		
15	DAVON-OH	D	69.00	13.20	
16	DELANO-OH	D	138.00	69.00	13.20
17		D	13.20	4.00	
18	DELAWARE (CSP)-OH	T	138.00	69.00	13.09
19		T	138.00	40.00	13.80
20		T	138.00	35.40	13.80
21		T	138.00	34.50	13.80
22		T	138.00	13.80	
23		T	138.00		
24		T	34.50		
25		T	13.20		
26	DUBLIN(CS)-OH	D	138.00	13.80	
27		D	13.80		
28	DUCK CREEK-OH	D	138.00	13.09	
29		D	23.00	13.09	
30	EAST BROAD STREET-OH	T	138.00	40.00	13.80
31		T	138.00	39.40	13.80
32		T	138.00		
33		T	40.00		
34		T	13.20		
35	ELK-OH	D	69.00	13.20	
36	ELLIOTT-OH	T	138.00	69.00	13.20
37	ETNA ROAD-OH	D	40.00	13.80	4.30
38		D	13.20		
39	FIFTH AVENUE-OH	D	138.00	39.40	13.80
40		D	13.80		

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	GAHANNA-OH	D	138.00	35.40	13.80
2		D	138.00	34.50	13.80
3		D	138.00	13.80	
4		D	13.20		
5	GALLOWAY ROAD-OH	D	69.00	13.80	
6		D	13.20		
7	GAY STREET-OH	D	138.00	13.80	13.80
8		D	13.80		
9	GENOA-OH	T	138.00	70.50	13.80
10		T	138.00	69.00	12.00
11		T	138.00	34.50	13.80
12		T	138.00		
13		T	69.00		
14	GROVES ROAD-OH	T	138.00	40.00	13.80
15		T	138.00	13.80	
16		T	138.00	13.80	13.80
17		T	138.00		
18		T	46.00		
19		T	40.00	13.80	
20		T	13.80		
21	HALL-OH	D	138.00	13.80	
22		D	13.80		
23	HANERS-OH	D	69.00	13.09	
24		D	13.20		
25	HARMAR-OH	D	23.00	4.36	
26	HARMAR HILL-OH	D	138.00	13.09	
27	HARRISON-OH	T	138.00	69.00	13.80
28	HESS STREET-OH	D	138.00	13.80	
29		D	138.00		
30		D	13.80		
31	HIGHLAND (CS)-OH	D	69.00	13.20	
32		D	69.00		
33		D	13.20		
34	HILLIARD-OH	D	69.00	13.80	
35		D	69.00		
36		D	13.20		
37					
38					
39					
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1	HUNTLEY-OH	T	138.00	69.50	13.09
2		T	138.00	13.80	
3		T	138.00		
4		T	69.00	13.80	
5		T	13.20		
6	HYATT-OH	T	345.00	137.50	13.80
7		T	138.00	35.40	13.80
8	IDAHO-OH	D	69.00	12.00	
9	JEFFERSON (CS)-OH	D	69.00	13.20	
10		D	13.20		
11	JUG STREET-OH	T	345.00	137.50	13.80
12		T	138.00	35.40	13.80
13	KARL ROAD-OH	D	138.00	13.80	13.80
14		D	13.80		
15		D	13.20		
16	KENNY-OH	D	138.00	13.80	13.80
17		D	13.20		
18	KIMBERLY-OH	D	138.00	13.09	
19	KIRK-OH	T	345.00	138.00	13.00
20		T	138.00	69.00	34.00
21		T	138.00	34.50	13.00
22		T	34.50		
23	LAYMAN-OH	D	138.00	13.09	
24	LAZELLE-OH	D	69.00	13.80	
25		D	13.20		
26	LEE-OH	D	69.00	12.00	
27		D	13.20		
28	LICK-OH	T	138.00	69.00	13.20
29		T	138.00		
30		T	69.00		
31		T	34.50	12.00	
32		T	13.20		
33	LINCOLN STREET-OH	D	69.00	13.80	
34	LINWORTH-OH	D	138.00	40.00	13.80
35		D	138.00	13.80	
36		D	13.20		
37	LIVINGSTON AVENUE-OH	D	40.00	13.00	
38	MADISON (CS)-OH	D	69.00	13.80	
39		D	69.00		
40					

Name of Respondent Ohio 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

SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	MALISZEWSKI 138 KV-OH	T	138.00	35.40	13.80
2		T	138.00	34.50	13.80
3		T	34.50		
4	MALISZEWSKI 765 KV-OH	T	765.00	138.00	13.80
5	MARION ROAD-OH	T	138.00	40.00	13.00
6		T	138.00	39.40	13.80
7		T	138.00		
8		T	40.00	13.00	
9		T	13.80	13.80	
10		T	13.20		
11	MCCOMB (CS)-OH	T	138.00	39.40	13.80
12		T	138.00		
13		T	13.20		
14	MEIGS (CS)-OH	D	69.00	13.09	
15		D	69.00	13.00	
16		D	69.00		
17		D	13.20		
18	MIFFLIN-OH	D	138.00	13.80	
19		D	13.20		
20	MILL CREEK (CSP)-OH	D	138.00	24.80	
21		D	138.00	13.09	
22	MORSE ROAD-OH	D	138.00	13.80	13.80
23		D	138.00		
24		D	13.20		
25	MOUND STREET-OH	D	138.00	13.80	13.80
26		D	13.80		
27	OSU-OH	D	138.00	13.80	
28		D	13.80		
29	PARK-OH	D	69.00	13.80	
30		D	13.20		
31	PARSONS-OH	D	40.00	13.80	
32		D	13.80		
33	PEACH MOUNT-OH	D	34.50	12.00	
34		D	13.20	4.00	
35	POLARIS-OH	D	138.00	35.40	13.80
36		D	34.50		
37	PORTERFIELD-OH	D	138.00	13.09	
38					
39					
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	POSTON-OH	T	138.00	69.00	13.40
2		T	138.00		
3		T	69.00	13.20	
4		T	69.00	13.09	
5		T	69.00	12.00	
6	RARDEN-OH	D	69.00	34.50	13.00
7	RAVEN-OH	D	69.00	13.20	
8	RENO-OH	D	138.00	13.09	
9	REYNOLDSBURG-OH	D	40.00	13.20	4.15
10		D	7.50		
11	RIO-OH	D	138.00	13.20	
12		D	13.20		
13	RIVERVIEW (CSP)-OH	D	138.00	13.80	
14		D	138.00		
15	ROBERTS-OH	T	345.00	138.00	34.50
16		T	345.00	137.50	13.80
17		T	138.00	13.80	
18		T	13.20		
19		T	13.20		
20	ROSS-OH	T	138.00	69.00	13.20
21		T	138.00	34.50	12.00
22		T	138.00		
23		T	69.00	13.00	
24		T	69.00		
25		T	13.20		
26	ROZELLE-OH	D	138.00	13.09	
27	SAINT CLAIR AVENUE (CS)-OH	D	138.00	40.00	13.00
28		D	138.00	13.80	13.80
29		D	138.00		
30	SARDINIA-OH	D	69.00	13.20	
31		D	13.20		
32	SAWMILL-OH	T	138.00	69.00	13.00
33		T	138.00	34.50	13.80
34		T	138.00	13.80	
35		T	138.00		
36	SCIOTO TRAIL (CS)-OH	D	138.00	13.20	7.24
37	SCIPPO-OH	D	138.00	13.09	
38					
39					
40					

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	SEAMAN-OH	T	138.00	69.00	13.09
2		T	69.00	13.20	
3		T	69.00	13.09	
4		T	69.00		
5	SHANNON-OH	D	138.00	13.80	
6		D	13.80		
7	SLATE MILLS-OH	D	69.00	13.20	
8	STROUDS RUN-OH	T	138.00	69.00	13.20
9		T	138.00	69.00	12.00
10	SUNBURY-OH	D	34.50	13.20	4.15
11	TAYLOR-OH	D	138.00	34.50	13.80
12	TRABUE-OH	D	138.00	69.50	13.80
13		D	138.00	13.80	
14		D	13.80		
15	TRENT-OH	D	138.00	34.50	13.80
16	VIGO-OH	D	69.00	13.20	
17		D	69.00	13.09	
18	VINE-OH	D	138.00	13.80	
19		D	138.00	13.80	13.80
20		D	138.00		
21		D	13.20		
22	WAVERLY-OH	T	138.00	69.00	13.53
23		T	138.00	69.00	13.20
24		T	138.00		
25		T	13.20		
26	WEST-OH	D	46.00		
27		D	40.00	13.80	
28		D	40.00	13.20	
29	WESTERVILLE-OH	D	69.00	13.80	
30	WHITE ROAD-OH	D	138.00	13.80	
31	WILKESVILLE-OH	D	138.00	13.09	
32	WILSON ROAD-OH	T	138.00	39.40	13.80
33		T	138.00	13.80	13.80
34		T	138.00		
35		T	46.00		
36		T	13.20		
37	WOLF CREEK (CSP)-OH	T	138.00	133.20	7.20
38		T	138.00	23.60	
39		T	138.00	13.09	
40					

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

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1	ZUBER-OH	D	138.00	13.80	
2		D	13.80		
3					
4					
5	23 STATIONS UNDER 10 MVA	T/D			
6					
7	COMMONLY OWNED SUBSTATIONS				
8	#5 CORRIDOR/FRANKLIN CO. OH - NOTE A	UNATTENDED T	345.00		
9	#50 BECKJORD/NEW RICHMOND. OH - NOTE B	ATTENDED T	22.00	345.00	
10	#52 STUART/ADAMS CO. OH - NOTE A	SUPERVISORY			
11		CONTROL T	345.00	138.00	
12	SEE NOTE B	MONITOR T	22.00	345.00	
13	SEE NOTE A	MONITOR T	22.00	345.00	
14	SEE NOTE D	ATTENDED T	22.00	345.00	
15	SEE NOTE E	SUPERVISORY			
16		CONTROL T	345.00		
17	#52 PIERCE/CLERMONT CO. OH - NOTE B	ATTENDED T	345.00		
18	#50 GREEN/GAYTON. OH - NOTE B	SUPERVISORY			
19		CONTROL T	345.00		
20	#61 FOSTER/WARREN CO. OH - NOTE B	UNATTENDED T	345.00		
21	#62 ZIMMER/CLERMONT CO. OH - NOTE A & C	ATTENDED T	22.00	345.00	
22	#66 CONESVILLE/CONESVILLE. OH - NOTE A	ATTENDED T	22.00	345.00	
23	#71 BIXBY/GROVEPORT. OH - NOTE A	UNATTENDED T	345.00		
24	#74 BEATTY RD/GROVE CITY. OH - NOTES A & B	UNATTENDED T	345.00		
25	#241 TERMINAL/CINCINNATI. OH - NOTE C	ATTENDED T	345.00		
26	#243 PORT UNION/BUTLER CO. OH - NOTE C	ATTENDED T	345.00		
27	#245 DON MARQUIS/PIKE CO. OH - NOTE B	UNATTENDED T	345.00		
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
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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.
						1
129	1					2
			STATCAP	1	18	3
20	1					4
6	1					5
6	1					6
3		1				7
11	1					8
10	1					9
20	1					10
14	2					11
16	2					12
20	1					13
11	1					14
20	1					15
8	1	1				16
11		1				17
20	1					18
42	2					19
13	1					20
20	1					21
20	1					22
19	2					23
20	1					24
20	1					25
11	1					26
			STATCAP	1	4	27
25	1					28
20	1					29
3	1					30
20	1					31
20	1					32
			STATCAP	1	29	33
129	1					34
20	1					35
			STATCAP	1	13	36
75	1					37
20	1					38
30	1					39
11	1					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
9	1					2
20	1					3
25	1					4
11	1					5
8	1					6
			STATCAP	1	10	7
84	1					8
13	1					9
448	2					10
40	2					11
11	1					12
130	1					13
9	1					14
75	1					15
10	2					16
11	1					17
11	2					18
22	1					19
9	1					20
9	1					21
			STATCAP	1	14	22
22	1					23
8	1					24
			STATCAP	1	41	25
40	2					26
90	1					27
20	1					28
9	1					29
20	2					30
20	1					31
11	1					32
			STATCAP	1	11	33
6	2					34
20	1					35
2250	3	1				36
			REACTOR	3	100	37
900	2					38
13	2					39
11	1					40

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Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
11	1					1
5	1					2
			STATCAP	1	16	3
50	1					4
56	1					5
37	1					6
			STATCAP	1	14	7
22	1					8
11	1					9
9	1					10
14	2					11
			STATCAP	1	16	12
50	1					13
			STATCAP	1	29	14
25	1					15
450	1					16
450	1					17
150		1				18
60	1					19
			STATCAP	1	72	20
90	1					21
			STATCAP	1	14	22
11	1					23
			STATCAP	1	14	24
25	1					25
7	2					26
20	1					27
			STATCAP	1	20	28
20	1					29
55	2					30
25	1					31
5	1					32
9	1					33
9	1					34
			STATCAP	1	4	35
11	1					36
20	1					37
11	1					38
						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.
84	1					1
25		1				2
20	1					3
			STATCAP	1	22	4
50	1					5
50	1					6
			STATCAP	1		7
42	2					8
20	1					9
22	1					10
9	1					11
7	1					12
19	2					13
25	1					14
6	1					15
22	1					16
11	1					17
11	1					18
18	2					19
			STATCAP	1	14	20
75	1					21
9	1					22
			STATCAP	1	14	23
8	3	1				24
5		1				25
7	1					26
			STATCAP	1	14	27
450	1					28
20	1					29
130	1					30
			STATCAP	1	20	31
130	1					32
			STATCAP	1	43	33
6	1					34
			STATCAP	1	13	35
20	1					36
			REACTOR	3	300	37
			STATCAP	2	115	38
130	1					39
1		1				40

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.

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20	1					1
25	1					2
22	1					3
20	1					4
6	1					5
75	1					6
35	1					7
	1					8
10	6	2				9
13	1					10
			STATCAP	1	14	11
			REACTOR	3	300	12
56	1					13
22	1					14
84	1					15
9	1					16
129	1					17
25	1					18
3	1					19
20	1					20
11	1					21
90	1					22
90	1					23
			STATCAP	2	115	24
9	1					25
			STATCAP	1	12	26
11	1					27
11	1					28
15	2					29
			STATCAP	1	18	30
75	1					31
			STATCAP	1	121	32
900	2					33
1500	3					34
			REACTOR	6	600	35
60	2					36
			STATCAP	1	14	37
22	1					38
19	3					39
			STATCAP	1	27	40

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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25	1					1
22	1					2
15	2					3
15	2					4
22	1					5
11	1					6
			STATCAP	1	14	7
11	1					8
			STATCAP	1	10	9
20	1					10
22	1					11
56	1					12
13	1					13
5	1					14
11	1					15
20	1					16
			REACTOR	9	900	17
750		3				18
3000	3					19
20	1					20
14	2					21
33	2					22
25	1					23
22	1					24
20	1					25
11	1					26
75	1					27
33	3					28
			STATCAP	1	53	29
5		1				30
20	1					31
20	1					32
11	1					33
20	1					34
11	1					35
9	2					36
150	1					37
450	1					38
84	1					39
20	1					40

Name of Respondent Ohio 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

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.
20	1					1
			STATCAP	1	14	2
90	1					3
60	2					4
20	1					5
			STATCAP	1	43	6
			STATCAP	1	10	7
40	2					8
			STATCAP	1	14	9
14	2					10
			STATCAP	1	14	11
128	1					12
56	1					13
39	1					14
			STATCAP	1	14	15
20	1					16
			STATCAP	1	7	17
56	1					18
			STATCAP	1	11	19
9	1					20
9	1					21
22	1					22
			STATCAP	1	10	23
39	1					24
22	1					25
			STATCAP	1	18	26
15	1					27
90	1					28
			STATCAP	1	18	29
16	2					30
84	1					31
90	1					32
			STATCAP	1	43	33
			STATCAP	2	31	34
20	1					35
20	1					36
16	2					37
20	1					38
11	1					39
50	1					40

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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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
80	2					1
25	1					2
			STATCAP	1	58	3
11		1				4
3	1					5
			STATCAP	1	12	6
40	1					7
600	3					8
20	1					9
29	2					10
40	1					11
7	1					12
11	1					13
			STATCAP	1	13	14
20	1					15
			STATCAP	1	13	16
50	1					17
			STATCAP	1	5	18
11	1					19
47	2					20
56	1					21
			STATCAP	1	10	22
30	1					23
20	1					24
11	1					25
11	1					26
20	1					27
22	1					28
448	1					29
90		1				30
112	2					31
20		1				32
20		1				33
50		1				34
3		1				35
3		1				36
3		1				37
20	1					38
20	1					39
			STATCAP	1	14	40

SUBSTATIONS (Continued)

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10	1					1
5	1					2
			STATCAP	1	10	3
21	2					4
11	2					5
9	1					6
25	1					7
			STATCAP	1	11	8
9	1					9
20	1					10
20	1					11
22	1					12
9	1					13
11	1					14
60	1					15
22	1					16
22	1					17
6	1					18
			STATCAP	1	14	19
10	6					20
50	1					21
50	6					22
20	1					23
			STATCAP	1	14	24
20	1					25
9	1					26
20	1					27
22	1					28
80	2					29
22	1					30
39	1					31
20	1					32
6	1					33
			STATCAP	1	10	34
22	1					35
16	2					36
11	1					37
25	1					38
84	1					39
			STATCAP	1	19	40

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
75	1					1
22	1					2
13	1					3
50	1					4
15	1					5
13	1					6
150	1					7
75	1					8
5	1					9
			STATCAP	1	10	10
50	2					11
39	1					12
			STATCAP	1	14	13
1350	2					14
2250	3	1				15
75	1					16
30	1					17
20	1					18
39	1					19
3		1				20
84	1					21
8		1				22
11	1					23
40	2					24
			STATCAP	1	12	25
20	1					26
75	1					27
			STATCAP	1	18	28
30	2					29
			STATCAP	1		30
130	1					31
60	1					32
11	1					33
22	1					34
25	1					35
			STATCAP	1	6	36
40	2					37
						38
						39
						40

Name of Respondent Ohio 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

SUBSTATIONS (Continued)

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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.
129	1					1
70	4					2
			STATCAP	1	67	3
9	1					4
20	1					5
5	1					6
50	1					7
60	1					8
22	1					9
5	1					10
			STATCAP	1	10	11
672	1					12
11	1					13
450	1					14
450	1					15
448	1					16
			STATCAP	1	58	17
19	2					18
9	1					19
11	1					20
			STATCAP	1	10	21
20	1					22
			STATCAP	1	13	23
30	3					24
33	3	1				25
			STATCAP	1	14	26
112	1					27
20	1					28
5	1					29
20	1					30
30	1					31
22	1					32
84	1					33
20	1					34
42	1					35
30	3					36
20	1					37
			STATCAP	1		38
			STATCAP	1	14	39
22	1					40

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15	1					1
40	2					2
20	1					3
6	3					4
6	3					5
20	1					6
8		1				7
			STATCAP	1	86	8
150	1					9
450	1					10
60	1					11
3	2					12
130	1					13
4	1					14
50	1					15
9	1					16
6	1					17
90	1					18
11	1					19
			STATCAP	1	19	20
335	4					21
11	2					22
20	1					23
90	1					24
92	6	1				25
			STATCAP	1		26
11	1					27
			STATCAP	1	10	28
1		1				29
20	1					30
20	1					31
			STATCAP	1	14	32
25	1					33
22	1					34
6	1					35
			STATCAP	1	16	36
130	1					37
84	1					38
30	1					39
			STATCAP	1	53	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.
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11	1					1
130	1					2
22	1					3
400	1					4
115	1					5
90	1					6
30	1					7
			STATCAP	1	43	8
130	1					9
20	1					10
22	1					11
			STATCAP	1	62	12
25	1					13
			STATCAP	1	10	14
56	1					15
90	1					16
75	1					17
			STATCAP	1	58	18
6	1					19
4	1					20
			STATCAP	1	22	21
11	1					22
			STATCAP	1	14	23
129	1					24
25	1					25
			STATCAP	2	5	26
11	1					27
197	2					28
			STATCAP	1	72	29
			STATCAP	1	14	30
265	2					31
			STATCAP	1	46	32
20	1					33
20	2					34
			STATCAP	1	10	35
22	1					36
90	1					37
25	1					38
900	2					39
130		1				40

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			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
200	1					1
20	1					2
30	1					3
			STATCAP	1	53	4
			STATCAP	1	13	5
129	1					6
15	1					7
31	2					8
			STATCAP	1	72	9
11	1					10
20	1					11
25	1					12
22	1					13
			STATCAP	1	14	14
20	1					15
20	1					16
11	1					17
20	1					18
50	1					19
25	1					20
20	1					21
			STATCAP	2	50	22
130	1					23
25	1					24
			STATCAP	1	58	25
						26
1032	204					27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						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.
						1
56	1					2
			STATCAP	1	14	3
56	1					4
20	1					5
			STATCAP	1	14	6
			STATCAP	1	4	7
20	1					8
168	2					9
			STATCAP	4	14	10
1010	2	1				11
100	2					12
56	1					13
30		1				14
50	1					15
			STATCAP	2	7	16
40	2					17
50	1					18
	3					19
			STATCAP	1	7	20
9	1					21
11	1					22
			STATCAP	1		23
50	1					24
167	2	1				25
			STATCAP	1	72	26
			STATCAP	5	36	27
83	2					28
42		1				29
84	1					30
			STATCAP	1	11	31
			STATCAP	2	13	32
						33
						34
						35
						36
						37
						38
						39
						40

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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
675	1					1
675	1					2
42	1	1				3
158	2					4
25		2				5
7		2				6
22		1				7
9		3				8
9		1				9
33		1				10
9		1				11
9		1				12
9		1				13
			STATCAP	2	6	14
50	1					15
			STATCAP	1	5	16
			STATCAP	1	4	17
100	2					18
25	1					19
42	2					20
			STATCAP	1	3	21
100	2					22
50		1				23
20	1					24
20	1					25
2	1					26
252	3					27
			STATCAP	4	22	28
			STATCAP	4	31	29
50	1					30
60	2					31
30	1					32
			STATCAP	1	48	33
			STATCAP	1	12	34
			STATCAP	3	10	35
	1					36
56	2					37
			STATCAP	1		38
168	2					39
15	1					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.
675	1					1
11		1				2
			STATCAP	2	173	3
11	1					4
11	1					5
			STATCAP	1		6
20	1					7
675	1					8
560	1					9
50	1	1				10
			STATCAP	1	115	11
45	2					12
92	2	1				13
			STATCAP	2	14	14
11	1					15
34	1					16
5		1				17
130	1					18
25	1					19
50	1					20
25	1					21
42	1					22
			STATCAP	1	18	23
			STATCAP	1	6	24
			STATCAP	2	11	25
150	3					26
			STATCAP	3	14	27
22	1					28
1		1				29
83	2					30
42		1				31
			STATCAP	1	72	32
			STATCAP	1	22	33
			STATCAP	4	12	34
22	1					35
75	1					36
63	3					37
			STATCAP	2	10	38
42	1					39
			STATCAP	1	3	40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio 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.
50	1					1
53	2					2
50	1					3
			STATCAP	2	6	4
62	3					5
			STATCAP	3	10	6
252	3					7
			STATCAP	6	38	8
90	1					9
130	1					10
92	2					11
			STATCAP	2		12
			STATCAP	2		13
75	1					14
50	1					15
168	2	1				16
			STATCAP	1		17
			STATCAP	1	11	18
22		2				19
			STATCAP	5	17	20
92	2					21
			STATCAP	2	14	22
25	1					23
			STATCAP	1	4	24
11	2					25
20	1					26
56	1					27
167	4					28
			STATCAP	1	62	29
			STATCAP	2	13	30
45	2					31
			STATCAP	1	13	32
			STATCAP	2	5	33
70	3					34
			STATCAP	1	10	35
			STATCAP	2	7	36
						37
						38
						39
						40

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.
84	1					1
83	2					2
			STATCAP	1	53	3
64	2					4
			STATCAP	4	14	5
600	2					6
50	1					7
11	1					8
21	2					9
			STATCAP	1	3	10
450	1					11
50	1					12
251	3					13
			STATCAP	5	25	14
			STATCAP	1	4	15
168	2					16
			STATCAP	2	10	17
40	2					18
560	1					19
90	1					20
42	1					21
			STATCAP	1	4	22
20	1					23
45	2					24
			STATCAP	1	4	25
11	1					26
			STATCAP	1	3	27
90	3					28
			STATCAP	1	43	29
			STATCAP	1	18	30
5		1				31
			STATCAP	2	7	32
60	2					33
42	1					34
42	1					35
			STATCAP	2	7	36
44	2					37
20	1					38
			STATCAP	1	7	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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
50		1				1
50	1					2
			STATCAP	1	7	3
750	3	1				4
83	1					5
167	2					6
			STATCAP	1	53	7
13		1				8
17	6					9
			STATCAP	5	20	10
100	2					11
			STATCAP	1	86	12
			STATCAP	2	7	13
9	1					14
11	1					15
			STATCAP	2	10	16
			STATCAP	1	6	17
150	3					18
			STATCAP	2	3	19
40	2					20
50	2					21
242	3					22
			STATCAP	1	72	23
			STATCAP	6	43	24
168	2					25
			STATCAP	2	7	26
50	1					27
			STATCAP	1	7	28
34	1					29
			STATCAP	1	3	30
40	2					31
			STATCAP	2	6	32
6	1					33
6	1					34
100	2					35
			STATCAP	2	14	36
14	1					37
						38
						39
						40

Name of Respondent Ohio 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

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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
94	2					1
			STATCAP	1	50	2
11	1	1				3
11		1				4
6		1				5
38	2					6
13	1					7
20	1					8
10	1					9
			STATCAP	1	3	10
34	2					11
			STATCAP	1	3	12
45	2					13
			STATCAP	1	36	14
675	1					15
560	1					16
84	2					17
			REACTOR		40	18
			STATCAP	1	4	19
116	3					20
13		1				21
			STATCAP	1	65	22
2		1				23
			STATCAP	1	14	24
			STATCAP	3	11	25
20	1					26
42		1				27
177	2	1				28
			STATCAP	1	72	29
11	1					30
			STATCAP	1	3	31
90	1					32
149	2					33
25	1					34
			STATCAP	1	86	35
30	1					36
20	1					37
						38
						39
						40

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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
90	1					1
6		1				2
20	1					3
			STATCAP	1	29	4
92	2					5
			STATCAP	2	13	6
11	1					7
30	1					8
84	1					9
18	2					10
47	1					11
129	1					12
83	2					13
			STATCAP	2	14	14
47	1					15
11		1				16
20	1					17
92	2					18
93	1					19
			STATCAP	1	86	20
			STATCAP	5	29	21
30	1					22
30	1					23
			STATCAP	1	58	24
			STATCAP	2	5	25
			STATCAP	1	4	26
6		1				27
28	1					28
45	2					29
50	1					30
11	1					31
83	2	1				32
75	1					33
			STATCAP	1	72	34
			STATCAP	1	11	35
			STATCAP	2	7	36
187	1					37
20	1					38
20	1					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.
50	1					1
			STATCAP	1	7	2
						3
						4
156	27					5
						6
						7
						8
504	1					9
						10
250	1					11
1920	3					12
640	1					13
900		1				14
						15
						16
						17
						18
						19
						20
1955	2					21
910	1					22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Schedule Page: 426.14 Line No.: 1 Column: a

On December 31, 2011, AEP affiliates Columbus Southern Power Company and Ohio Power Company were merged into one company, Ohio Power Company.

Schedule Page: 426.22 Line No.: 7 Column: a

SUBSTATION NOTES:
- For Commonly Owned Substations as noted:
- Applies to page 426.22 lines 7 - 27

Equipment at these substations is co-owned with The Duke Energy, The Dayton Power and Light Company (DP&L), and the Respondent (OPCO). Expenses are shared on the basis of ownership which may vary by commonly owned substation. The co-owners are not associated companies. The percent of ownership at the substations referenced by the footnotes are:

Company	Duke Energy	DP&L	OPCO
Footnote:			
(A)	33-1/3%	33-1/3%	33-1/3%
(B)	30%	35%	35%
(C)	28%	36%	36%
(D)	40.3%	30.7%	29%
(E)	38.5%	41.3%	20.2%

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 - Maintenance	AEPSC	935	446,023
3	Administrative and General Expenses - Operation	AEPSC	Various (1)	22,037,763
4	Administrative and General Expenses - Operation	PSO	920-922, 930.1	713,500
5	Administrative and General Expenses - Operation	SWEPCO	920-922, 926	1,137,079
6	Administrative and General Expenses - Operation	TCC	920-922, 924-926	724,293
7	Assets & Other Debits - Current & Accrued Assets	APCO	152, 154, 163	570,740
8	Assets & Other Debits - Deferred Debits	AEP Pro Serv, Inc.	186	271,748
9	Assets & Other Debits - Deferred Debits	APCO	183 - 186, 188	706,413
10	Assets & Other Debits - Deferred Debits	I&M	184, 186, 188	2,900,041
11	Assets & Other Debits - Deferred Debits	KPCO	184, 186, 188	700,819
12	Assets & Other Debits - Deferred Debits	PSO	184, 186, 188	2,525,260
13	Assets & Other Debits - Deferred Debits	SWEPCO	184 - 186, 188	3,248,189
14	Assets & Other Debits - Deferred Debits	TCC	184, 186, 188	2,493,831
15	Assets & Other Debits - Deferred Debits	TNC	184, 186, 188	983,597
16	Assets & Other Debits - Deferred Debits	WPCO	184 - 186, 188	265,846
17	Assets & Other Debits - Utility Plant	I&M	107, 108	278,246
18	Assets & Other Debits - Utility Plant	KPCO	107, 108	718,567
19	Assets & Other Debits - Utility Plant	PSO	107, 108	318,016
20	**Non-power Goods or Services Provided for Affiliate**			
21	Administrative and General Expenses - Operation	I&M	Various (16)	654,325
22	Assets and Other Debits - Utility Plant	APCO	107, 108	392,920
23	Assets and Other Debits - Utility Plant	I&M	107, 108	440,121
24	Assets and Other Debits - Utility Plant	KPCO	107, 108	333,427
25	Assets and Other Debits - Utility Plant	OHTCO	107, 108	19,950,837
26	Assets and Other Debits - Utility Plant	WPCO	107, 108	2,249,790
27	Coal Transloading	APCO	456	941,920
28	Coal Transloading	I&M	456	32,639,336
29	Distribution Expenses - Maintenance	APCO	592 - 598	959,265
30	Distribution Expenses - Maintenance	KPCO	592 - 595, 597, 598	359,885
31	Distribution Expenses - Maintenance	WPCO	591 - 598	402,897
32	Distribution Expenses - Operation	WPCO	Various (17)	735,174
33	Emission Allowance Sales	I&M	158.1, 411.8, 411.9	4,276,097
34	Emission Allowance Sales	KPCO	158.1, 411.8, 411.9	5,033,939
35	Fleet and Vehicle Charges	APCO	Various (4)	2,195,093
36	Materials and Supplies	APCO	Various (18)	4,226,673
37	Materials and Supplies	I&M	Various (19)	1,716,412
38	Materials and Supplies	KPCO	Various (20)	590,626
39	Materials and Supplies	PSO	Various (21)	354,297
40	Materials and Supplies	TCC	Various (22)	261,160
41	Materials and Supplies	WPCO	Various (23)	327,128
42				
1	**Non-power Goods or Services Provided by Affiliated**			
2	Assets & Other Debits - Utility Plant	SWEPCO	107, 108	374,326

Name of Respondent Ohio 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

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)
3	Assets & Other Debits - Utility Plant	WPCO	107, 108	250,280
4	Audit Services	AEPSC	920	2,481,190
5	Barging	I&M	151	37,111,608
6	Central Machine Shop	APCO	Various (2)	3,302,589
7	Civil & Political Activities and Other Svcs	AEPSC	426.1, 426.3-426.5	3,375,390
8	Construction Services	AEPSC	107, 108	66,454,666
9	Corporate Accounting	AEPSC	920	6,668,851
10	Corporate Communications	AEPSC	920	2,549,709
11	Corporate Planning & Budgeting	AEPSC	920	2,885,598
12	Customer Accounts Expenses	AEPSC	901-905	36,457,812
13	Customer and Distribution Services	AEPSC	920	984,446
14	Customer Service and Informational Expenses	AEPSC	907, 908, 910	1,023,180
15	Distribution Expenses - Maintenance	AEPSC	590-595, 597	3,001,942
16	Distribution Expenses - Maintenance	PSO	593	903,144
17	Distribution Expenses - Maintenance	SWEPCO	592-595, 597	897,440
18	Distribution Expenses - Maintenance	TCC	592-596	691,730
19	Distribution Expenses - Operation	AEPSC	Various (3)	11,300,572
20	**Non-power Goods or Services Provided for Affiliate**			
21	Other Operating Revenues	APCO	454, 456	763,919
22	Power Prod Exp - Steam Power Gen - Operation	APCO	500-502, 506	952,209
23	Rail Car Lease	APCO	151	1,960,157
24	Rail Car Lease	I&M	151	889,391
25	Rail Car Lease	SWEPCO	151	320,787
26	Rail Car Maintenance	I&M	417	3,342,737
27	Rail Car Maintenance	PSO	417	281,483
28	Rail Car Maintenance	SWEPCO	417	2,101,850
29	Transmission Expenses - Maintenance	WPCO	568-571	396,406
30	Urea	APCO	154, 186	11,012,376
31	Urea	KPCO	154, 186	1,163,029
32	Use of Jointly Owned Facilities	OHTCO	456	267,126
33	Administrative and General Expenses - Operation	AEP T&D Services, LLC	920, 930.2	525,467
34	Assets and Other Debits - Utility Plant	Cardinal Operating Co	107, 108	486,593
35	Building and Property Leases	AEPSC	454	11,195,333
36	Fleet and Vehicle Charges	AEPSC	Various (4)	1,721,759
37	Power Prod Exp - Steam Power Gen - Maintenance	Cardinal Operating Co	510 - 514	634,135
38	Power Prod Exp - Steam Power Gen - Operation	Cardinal Operating Co	500, 501, 505, 506	891,196
39	Urea	Cardinal Operating Co	154, 186	465,074
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1	**Non-power Goods or Services Provided by Affiliated**			
2	Emission Allowance Purchases	APCO	158.1, 411.9	2,198,790
3	Enviro Safety Health Facilities	AEPSC	920	3,751,388
4	Ethics & Compliance	AEPSC	920	256,127

Name of Respondent Ohio 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

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)
5	Factored Customer A/R Bad Debts	AEP Credit	426.5	14,135,551
6	Factored Customer A/R Expense	AEP Credit	426.5	6,176,052
7	Finance, Acctg. & Strategic Plng Admin	AEPSC	920	666,930
8	Fleet and Vehicle Charges	APCO	Various (4)	2,749,170
9	Fuel & Storeroom Services	AEPSC	151, 152, 163	8,224,371
10	Gypsum Storage	APCO	456	307,497
11	Human Resources	AEPSC	923	4,654,577
12	Information Technology	AEPSC	923	13,349,123
13	Leased Transmission Lines	WPCO	565	1,351,836
14	Legal GC/Administration	AEPSC	920	5,934,823
15	Liabilities and Other Credits - Deferred Credits	I&M	253	362,698
16	Materials and Supplies	APCO	Various (5)	2,113,817
17	Materials and Supplies	I&M	Various (6)	808,441
18	Materials and Supplies	KPCO	Various (7)	2,488,885
19	Materials and Supplies	OHTCO	107, 108, 930	3,964,575
20	**Non-power Goods or Services Provided for Affiliate**			
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1	**Non-power Goods or Services Provided by Affiliated**			
2	Materials and Supplies	PSO	Various (8)	456,517
3	Materials and Supplies	SWEPCO	Various (9)	373,938
4	Materials and Supplies	WPCO	Various (10)	2,073,993
5	O&M Services for Jointly Owned Facility - Amos	APCO	Various (11)	40,342,953
6	O&M Services for Jointly Owned Facility - Sporn	APCO	Various (12)	13,137,758

Name of Respondent Ohio 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

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.
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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)
7	Other Power Generation - Maintenance	AEPSC	553, 555 - 557	12,860,965
8	Other Power Generation - Operation	AEPSC	546 - 549	408,478
9	Power Prod Exp - Steam Power Gen - Maintenance	APCO	510 - 514	434,721
10	Rail Car Lease	APCO	186	853,594
11	Real Estate & Workplace Svcs	AEPSC	923	2,036,783
12	Regulatory Services	AEPSC	920	3,987,260
13	Relative Accuracy Test Audits	USTI	500	405,362
14	Research and Other Services	AEPSC	Various (13)	7,542,042
15	Risk and Strategic Initiatives	AEPSC	920	1,802,643
16	Simulator Learning Center	APCO	506	563,123
17	Steam Power Generation - Maintenance	AEPSC	510 - 514	11,168,641
18	Steam Power Generation - Operation	AEPSC	500 - 502, 505, 506	21,432,967
19	Supply Chain & Fleet Operations	AEPSC	923	579,485
20	**Non-power Goods or Services Provided for Affiliate**			
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1	**Non-power Goods or Services Provided by Affiliated**			
2	Transmission Expenses - Maintenance	AEPSC	Various (14)	1,929,103
3	Transmission Expenses - Operation	AEPSC	Various (15)	12,809,842
4	Treasury & Investor Relations	AEPSC	920	1,238,869
5	Urea	Cardinal Operating Co	154, 186	534,623
6	Utility Operations	AEPSC	920	2,331,670
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio 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)
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20	**Non-power Goods or Services Provided for Affiliate**			
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Schedule Page: 429 Line No.: 2 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 pole 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 services are made at cost and include no compensation for a return on investment.

Schedule Page: 429 Line No.: 3 Column: c

Various Account Listings as provided in Column (c):

Various (1) – 920, 921, 923-926, 928, 930.1, 930.2, 931

Various (2) – 107, 506, 512-514, 544

Various (3) – 580-584, 586, 588, 589

Various (4) – Cost 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.

Various (5) – 107, 108, 154, 163, 184, 186, 506, 511-514, 539, 553, 562, 569-571, 573, 580, 583, 586, 588, 592-596, 903, 930, 935

Various (6) – 107, 108, 154, 186, 506, 512-514, 531, 539, 562, 566, 570, 571, 588, 597, 903, 930, 935

Various (7) – 107, 154, 163, 511-513, 562, 566, 570, 571, 583, 585, 586, 588, 592-595, 902, 903, 935

Various (8) – 107, 154, 163, 512, 513, 930, 935

Various (9) – 107, 108, 154, 163, 512, 513, 593

Various (10) – 107, 108, 154, 163, 186, 570, 571, 583, 586, 592-594, 935

Various (11) – 152, 408.1, 421, 426.1, 426.3-426.5, 431, 500-502, 505-507, 510-514, 556, 557, 920, 921, 923-926, 930.1, 930.2, 931, 935

Various (12) – 152, 408.1, 421, 426.1, 426.3-426.5, 431, 500-502, 505-507, 510-514, 920, 921, 923-926, 928, 930.1, 930.2, 931, 935

Various (13) – 182.3, 183, 184, 186, 188

Various (14) – 568, 569, 569.1-569.3, 570-573

Various (15) – 560, 561.1-561.3, 561.5, 562, 563, 566, 567

Various (16) – 920-923, 930.1, 930.2, 931

Various (17) – 580, 582, 583, 586, 588, 589

Various (18) – 107, 108, 154, 163, 186, 502, 506, 511-514, 562, 570, 571, 586, 588, 592-594, 597, 902, 930, 935

Various (19) – 107, 108, 154, 163, 186, 506, 511, 512, 562, 570, 571, 592-595, 902, 921, 935

Various (20) – 107, 154, 163, 186, 511-513, 570, 571, 583, 588, 592, 935

Various (21) – 107, 154, 163, 186, 512-514, 593

Various (22) – 107, 154, 163, 186, 571, 592, 594

Various (23) – 107, 154, 186, 506, 511, 513, 570, 588, 592

Schedule	Page No.