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

Form 1 Approved
OMB No. 1902-0021
(Expires 2/29/2009)
Form 1-F Approved
OMB No. 1902-0029
(Expires 2/28/2009)
Form 3-Q Approved
OMB No. 1902-0205
(Expires 2/28/2009)

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

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

Exact Legal Name of Respondent (Company)	Year/Period of Report
Ohio Power Company	End of 2009/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 2009/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 Stephen J. Clark	06 Title of Contact Person Senior Staff Accountant
07 Address of Contact Person *(Street, City, State, Zip Code)* AEP Service Corporation, 1 Riverside Plaza, Columbus, Ohio 43215	

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

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 Joseph M. Buonaiuto	03 Signature	04 Date Signed *(Mo, Da, Yr)*
02 Title Controller	Joseph M. Buonaiuto	04/16/2010

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 2009/Q4

LIST OF SCHEDULES (Electric Utility)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Important Changes During the Year	108-109	
7	Comparative Balance Sheet	110-113	
8	Statement of Income for the Year	114-117	
9	Statement of Retained Earnings for the Year	118-119	
10	Statement of Cash Flows	120-121	
11	Notes to Financial Statements	122-123	
12	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
13	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
14	Nuclear Fuel Materials	202-203	
15	Electric Plant in Service	204-207	None
16	Electric Plant Leased to Others	213	
17	Electric Plant Held for Future Use	214	None
18	Construction Work in Progress-Electric	216	
19	Accumulated Provision for Depreciation of Electric Utility Plant	219	
20	Investment of Subsidiary Companies	224-225	
21	Materials and Supplies	227	
22	Allowances	228-229	
23	Extraordinary Property Losses	230	
24	Unrecovered Plant and Regulatory Study Costs	230	None
25	Transmission Service and Generation Interconnection Study Costs	231	None
26	Other Regulatory Assets	232	
27	Miscellaneous Deferred Debits	233	
28	Accumulated Deferred Income Taxes	234	
29	Capital Stock	250-251	
30	Other Paid-in Capital	253	
31	Capital Stock Expense	254	
32	Long-Term Debt	256-257	None
33	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
34	Taxes Accrued, Prepaid and Charged During the Year	262-263	
35	Accumulated Deferred Investment Tax Credits	266-267	
36	Other Deferred Credits	269	

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 2009/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".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	
38	Accumulated Deferred Income Taxes-Other Property	274-275	
39	Accumulated Deferred Income Taxes-Other	276-277	
40	Other Regulatory Liabilities	278	
41	Electric Operating Revenues	300-301	
42	Sales of Electricity by Rate Schedules	304	
43	Sales for Resale	310-311	
44	Electric Operation and Maintenance Expenses	320-323	
45	Purchased Power	326-327	
46	Transmission of Electricity for Others	328-330	
47	Transmission of Electricity by ISO/RTOs	331	
48	Transmission of Electricity by Others	332	None
49	Miscellaneous General Expenses-Electric	335	
50	Depreciation and Amortization of Electric Plant	336-337	
51	Regulatory Commission Expenses	350-351	
52	Research, Development and Demonstration Activities	352-353	
53	Distribution of Salaries and Wages	354-355	
54	Common Utility Plant and Expenses	356	
55	Amounts included in ISO/RTO Settlement Statements	397	None
56	Purchase and Sale of Ancillary Services	398	
57	Monthly Transmission System Peak Load	400	
58	Monthly ISO/RTO Transmission System Peak Load	400a	
59	Electric Energy Account	401	None
60	Monthly Peaks and Output	401	
61	Steam Electric Generating Plant Statistics	402-403	
62	Hydroelectric Generating Plant Statistics	406-407	
63	Pumped Storage Generating Plant Statistics	408-409	
64	Generating Plant Statistics Pages	410-411	None
65	Transmission Line Statistics Pages	422-423	None
66	Transmission Lines Added During the Year	424-425	

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 2009/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".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Substations	426-427	
68	Footnote Data	450	
	Stockholders' Reports Check appropriate box: [ ] Four copies will be submitted [ ] No annual report to stockholders is prepared		

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 2009/Q4

GENERAL INFORMATION

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

Joseph M. Buonaiuto, Controller
1 Riverside Plaza
Columbus, Ohio 43215

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

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 2009/Q4

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 beneficiearies 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 2009/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				
6	(a) Joint Control			
7	- Buckeye Power, Inc.			
8	(b) Joint Control			
9	- Appalachian Power Company			
10	(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 2009/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 shows the compensation earned by the chief executive officer and the five other most highly compensated executive officers of AEP at December 31, 2009:

Name and Principal Position (a)	Salary ($)(1) (b)	Bonus ($) (c)	Stock Awards ($)(2) (d)	Option Awards ($) (e)	Non-Equity Incentive Plan Compen-sation ($)(3) (f)	Change in Pension Value and Non-qualified Deferred Compen-sation Earnings ($)(4) (g)	All Other Compen-sation Earnings ($)(5) (h)	Total ($) (i)
Michael G. Morris — Chairman of the board, president and chief executive officer	1,254,808	—	5,265,750	—	—	446,490	572,230	7,539,278
Brian X. Tierney — Executive vice president and Chief Financial Officer	401,539	—	857,866	—	—	124,813	69,767	1,453,985
Carl L. English — Chief Operating Officer	552,115	—	1,848,128	—	—	108,781	74,965	2,583,989
Robert P. Powers — President-AEP Utilities	511,961	—	1,213,530	—	—	692,065	68,442	2,485,998
Susan Tomasky — President-Transmission	511,961	—	1,221,052	—	—	1,009,187	64,060	2,806,260
Holly Keller Koeppel (6) — Former Chief Financial Officer	498,077	—	1,320,048	—	—	264,759	315,082	2,397,966

(1) Amounts in the salary column are composed of executive salaries and additional days of pay earned for more than the standard 260 calendar work days and holidays.

(2) The amounts reported in this column relate to performance units granted under our Long-Term Incentive Plan. The amounts shown are based on the aggregate grant date fair value of the award computed in accordance with FASB ASC Topic 718. Depending on the Company's performance, the potential payout to the executives can range from 0% to 200% of the target number of performance units, including reinvested dividends, multiplied by the average closing price of AEP common stock for the last 20 trading days of the performance period. Therefore, the maximum amount payable to an executive is equal to 200% of the target award stated above, plus an amount equal to any reinvested dividends on the performance units multiplied by the percentage increase in AEP's share price from the grant date.

See Note 15 to the Consolidated Financial Statements included in our Form 10-K for the year ended December 31, 2009 for a discussion of the relevant assumptions used in calculating these amounts.

(3) The amounts shown in this column are annual incentive awards made under the Company's Senior Officer Incentive Plan. At the outset of each year, the HR Committee sets target bonuses and performance criteria that will be used to determine whether and to what extent executive officers will receive 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. However, as a result of Ms. Koeppel's separation from service as of December 31, 2009, she became entitled to the distribution of these benefits. No named executive officer received preferential or above-market earnings on deferred compensation. See Note 8 to the Consolidated Financial Statements included in our Form 10-K for the year ended December 31, 2009 for a discussion of the relevant assumptions.

(5) A detailed breakout of the amounts shown in the All Other Compensation column is shown below. These amounts include subsidiary director fees, tax gross-ups, and Company contributions to the Company's Retirement Savings Plan and the Company's Supplemental Retirement Savings Plan. Prior to October 2009, the Company reimbursed executives for the tax withholding for spouse travel on corporate aircraft to events that the spouse was invited to attend. This amount is included under tax gross-ups below. Effective November 2009, the HR Committee eliminated all tax gross-ups. The HR Committee also eliminated Company reimbursement for country club dues effective February 2009.

For Mr. Morris, Ms. Tomasky and Ms. Koeppel , the amount shown includes the aggregate incremental cost associated with their personal use of Company-provided aircraft of $447,818, $1,998 and $41,444, respectively. This amount is the incremental cost to the Company for their personal use of Company-provided aircraft, including all operating costs such as fuel, trip-related maintenance, on-board catering, landing/ramp fees and other miscellaneous variable costs. Fixed costs that do not change based on usage, such as pilot salaries, the lease costs for Company aircraft and the cost of maintenance not related to personal trips, are excluded. For reporting purposes, personal use of corporate aircraft includes the incremental cost of relocating aircraft to accommodate personal trips and the incremental costs of flights for Mr. Morris, Ms. Tomasky and Ms. Koeppel to attend outside board meetings for the public companies and government institution at which they serve as outside directors. Effective September 2009, the HR Committee eliminated personal use of Company provided aircraft to the extent that such use has an incremental cost to the Company, except for Mr. Morris who negotiated this as part of his employment agreement. Ms. Koeppel received a separation payment of $212,000 in accordance with an agreement reached with her in exchange for her releasing the Company from any and all claims.

(6) Ms. Koeppel resigned as the Company's Chief Financial Officer effective September 30, 2009, but continued her employment through 2009 in other capacities.

All Other Compensation

Type	Michael G. Morris	Brian X. Tierney	Carl L. English	Robert P. Powers	Susan Tomasky	Holly Keller Koeppel
Retirement Savings Plan Match	8,296	11,025	11,025	11,025	11,025	8,247
Supplemental Retirement Savings Plan Match	81,704	37,592	34,927	31,483	30,808	35,196
Tax Gross-Ups	5,845	-	525	3,436	-	1,661
Subsidiary Company Directors Fees	13,300	10,500	11,400	10,450	7,600	12,150
Director Life and Accident Insurance	803	-	-	-	-	-
Country and Dining Club Dues and Airline Club Dues	2,664	-	683	1,749	2,085	434
Financial Counseling and Tax Preparation	11,800	10,650	12,500	10,299	10,444	3,950
Personal Use of Company Aircraft	447,818	-	-	-	1,998	41,444
Health & Wellness Program Incentives	-	-	-	-	100	-
Relocation Payment	-	-	3,905	-	-	-
Separation Payment	-	-	-	-	-	212,000

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 2009/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	Michael G. Morris, Chairman of the Board	Columbus, Ohio
3	and Chief Executive Officer	
4		
5	Venita McCellon-Allen, Vice President	Columbus, Ohio
6	and Vice Chariman of the Board	
7		
8	Brian X. Tierney, Vice President, Vice Chariman of the Board	Columbus, Ohio
9	and Chief Financial Officer	
10		
11	Holly Keller Koeppel, Vice President	Columbus, Ohio
12	and Chief Financial Officer	
13		
14	Susan Tomasky, Vice President	Columbus, Ohio
15		
16	John B. Keane, Secretary	Columbus, Ohio
17		
18	Carl L. English, Vice President	Columbus, Ohio
19		
20	Dennis E. Welch, Vice President	Columbus, Ohio
21		
22	Nicholas K. Akins, Vice President	Columbus, Ohio
23		
24	Robert P. Powers, Vice President	Columbus, Ohio
25		
26	Richard E. Munczinski, Vice President	Columbus, Ohio
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29	Note: The Respondent does not have an Executive Committee	
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Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/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 106, 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 December 1, 2008	Village of Athalia, County of Lawrence, Ohio	Twenty-five (25) year franchise renewal expiring December 1, 2033	None
Renewed on February 17, 2009	City of Findlay, Hancock County, Ohio	Twenty-five (25) year franchise renewal expiring February 17, 2034	None
Renewed on March 3, 2009	Village of Bettsville, Seneca County, Ohio	Ten (10) year franchise renewal expiring March 3, 2019	None
Renewed on March 2, 2009, accepted by Ohio Power Company on April 22, 2009	Village of Crown City, Gallia County	Twenty-Five (25) year franchise renewal expiring March 2, 2034	None
Renewed on. September, 22, 2009	Village of Minerva, Ohio	Fifty (50) year franchise renewal expiring September 22, 2059	None
Renewed on. September 14, 2009	Village of Chatfield, Ohio	Fifty (50) year franchise renewal expiring September 14, 2059	None

2. None

3. Effective December 15, 2009, JMG Funding, a wholly owned subsidiary of Ohio Power Company (OPCo), transferred all of its assets and liabilities to OPCo. Included in the assets transferred were the property, plant and equipment relating to the flue gas desulfurization system located at the General James M. Gavin Generating Plant owned by OPCo. Prior to this transfer and during 2009, OPCo acquired 100% of the outstanding equity in JMG Funding from third parties. The memo with the proposed journal entries to clear the balance in account 102 was filed with FERC on March 8, 2010.

4. None

5. None

6. Public Service Commission of Ohio Authority (Case No. 09-314-EL-AIS)

   $500 million 5.375% pollution control bonds due 10/1/2021

7. None

8. Wage agreements at Cook Coal Terminal resulted in an increase of 4.35% for represented employees

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

10. None

11. (Reserved)

12. Not Used

13. Timothy K. Light resigned as Vice President effective January 12, 2009

Richard E. Munczinski resigned as Director and Vice President effective January 12, 2009

Timothy K. Light appointed as Vice President effective January 29, 2009

Richard E. Munczinski appointed as Director and Vice President effective January 29, 2009

L. Rahmond Staggers resigned as Secretary effective April 2, 2009

Karl G. Boyd resigned as Vice President – Distribution Region Operations effective June 30, 2009

John B. Keane appointed as Secretary effective April 2, 2009

Anne M. Vogel appointed as Assistant Secretary effective April 2, 2009

Edward M. Mowrer appointed as Vice President – Distribution Region Operations effective May 26, 2009

Scott M. Krawec resigned as Assistant Controller effective August 31, 2009

Holly Keller Koeppel resigned as Director, Chief Financial Officer and Vice President effective October 1, 2009

Brian X. Tierney resigned as Vice Chairman of the Board effective October 1, 2009

Venita McCellon-Allen appointed as Director, Vice Chairman of the Board and Vice President effective October 1, 2009

Brian X. Tierney appointed as Chief Financial Officer effective October 1, 2009

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 2009/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	9,681,247,631	8,179,322,972
3	Construction Work in Progress (107)	200-201	198,843,300	787,180,331
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		9,880,090,931	8,966,503,303
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	3,403,633,125	2,941,678,522
6	Net Utility Plant (Enter Total of line 4 less 5)		6,476,457,806	6,024,824,781
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)		6,476,457,806	6,024,824,781
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		11,297,100	53,724,192
19	(Less) Accum. Prov. for Depr. and Amort. (122)		7,696,502	8,888,951
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	733,802	733,802
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	18,353,956	20,826,342
24	Other Investments (124)		110,017,825	64,477,862
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)		28,002,578	38,971,736
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	125,317
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		160,708,759	169,970,300
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		1,983,938	935,641
36	Special Deposits (132-134)		20,265,539	27,506,421
37	Working Fund (135)		0	0
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	22,833,100
40	Customer Accounts Receivable (142)		41,466,757	66,392,690
41	Other Accounts Receivable (143)		19,342,616	25,156,723
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		2,664,623	3,667,419
43	Notes Receivable from Associated Companies (145)		438,351,719	0
44	Accounts Receivable from Assoc. Companies (146)		197,359,400	115,959,386
45	Fuel Stock (151)	227	327,108,624	181,786,183
46	Fuel Stock Expenses Undistributed (152)	227	9,757,875	5,117,530
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	106,233,086	96,157,125
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	27,606,927	32,088,716

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 2009/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		18,353,956	20,826,342
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)		3,498,105	10,042,995
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		1,342,284	4,508,000
60	Rents Receivable (172)		1,373,570	219,749
61	Accrued Utility Revenues (173)		15,021,345	18,238,560
62	Miscellaneous Current and Accrued Assets (174)		2,757	2,646
63	Derivative Instrument Assets (175)		76,808,083	88,757,615
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		28,002,578	38,971,736
65	Derivative Instrument Assets - Hedges (176)		1,242,281	3,631,382
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	125,317
67	Total Current and Accrued Assets (Lines 34 through 66)		1,239,743,749	635,743,648
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		14,055,847	13,088,000
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	738,637,107	445,237,298
73	Prelim. Survey and Investigation Charges (Electric) (183)		38,184,581	37,869,139
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	111,218,057	119,529,512
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)		7,870,697	8,497,490
82	Accumulated Deferred Income Taxes (190)	234	270,381,478	322,089,159
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		1,180,347,767	946,310,598
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		9,057,258,081	7,776,849,327

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 Rresubmission	/ /	end of 2009/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	321,201,454	321,201,454
3	Preferred Stock Issued (204)	250-251	16,626,400	16,627,400
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		727,834	727,903
7	Other Paid-In Capital (208-211)	253	1,122,421,493	535,911,816
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	1,908,802,890	1,697,961,963
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	0	0
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)	-118,458,118	-133,858,575
16	Total Proprietary Capital (lines 2 through 15)		3,251,321,953	2,438,571,961
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	0	0
19	(Less) Reaquired Bonds (222)	256-257	303,000,000	85,000,000
20	Advances from Associated Companies (223)	256-257	200,000,000	200,000,000
21	Other Long-Term Debt (224)	256-257	3,351,580,000	2,594,450,000
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		6,075,144	4,703,786
24	Total Long-Term Debt (lines 18 through 23)		3,242,504,856	2,704,746,214
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		16,926,418	19,603,502
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		2,619,088	3,804,585
29	Accumulated Provision for Pensions and Benefits (228.3)		260,503,584	277,747,439
30	Accumulated Miscellaneous Operating Provisions (228.4)		8,756,973	7,266,314
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		12,462,659	23,796,855
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		47,391	19,831
34	Asset Retirement Obligations (230)		94,221,275	89,316,435
35	Total Other Noncurrent Liabilities (lines 26 through 34)		395,537,388	421,554,961
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		182,847,868	193,674,940
39	Notes Payable to Associated Companies (233)		0	133,887,073
40	Accounts Payable to Associated Companies (234)		93,641,097	207,858,920
41	Customer Deposits (235)		22,409,338	24,332,687
42	Taxes Accrued (236)	262-263	65,111,264	186,717,476
43	Interest Accrued (237)		50,279,533	46,975,084
44	Dividends Declared (238)		61,005	61,009
45	Matured Long-Term Debt (239)		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 Rresubmission	/ /	end of 2009/Q4

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		1,868,825	209,153
48	Miscellaneous Current and Accrued Liabilities (242)		56,198,803	74,385,432
49	Obligations Under Capital Leases-Current (243)		5,755,994	6,862,744
50	Derivative Instrument Liabilities (244)		34,812,008	52,247,155
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		12,462,659	23,796,855
52	Derivative Instrument Liabilities - Hedges (245)		2,089,243	787,481
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		47,391	19,831
54	Total Current and Accrued Liabilities (lines 37 through 53)		502,564,928	904,182,468
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		0	0
57	Accumulated Deferred Investment Tax Credits (255)	266-267	1,967,498	2,916,950
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	30,545,865	40,635,629
60	Other Regulatory Liabilities (254)	278	17,369,004	11,980,316
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	234,470,859	192,655,821
63	Accum. Deferred Income Taxes-Other Property (282)		992,082,286	793,110,926
64	Accum. Deferred Income Taxes-Other (283)		388,893,444	266,494,081
65	Total Deferred Credits (lines 56 through 64)		1,665,328,956	1,307,793,723
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		9,057,258,081	7,776,849,327

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 2009/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	3,012,716,790	3,138,790,128		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	1,694,784,685	2,003,062,187		
5	Maintenance Expenses (402)	320-323	224,439,413	213,431,469		
6	Depreciation Expense (403)	336-337	307,382,084	224,666,648		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	3,514,476	466,377		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	20,477,686	18,070,794		
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)		1,663,129	32,137,365		
13	(Less) Regulatory Credits (407.4)		49,124	21,530,246		
14	Taxes Other Than Income Taxes (408.1)	262-263	193,436,946	191,890,475		
15	Income Taxes - Federal (409.1)	262-263	-199,646,971	81,041,949		
16	- Other (409.1)	262-263	-28,317,629	-7,417,477		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	653,973,341	284,123,530		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	260,867,188	240,319,382		
19	Investment Tax Credit Adj. - Net (411.4)	266	-437,912	-439,885		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)		35,943,626	16,968,541		
23	Losses from Disposition of Allowances (411.9)		4,129,102	6,486,186		
24	Accretion Expense (411.10)		7,904,895	5,756,850		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		2,586,456,003	2,774,470,995		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		426,260,787	364,319,133		

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 2009/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		Line No.
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)	
						1
3,012,716,790	3,138,790,128					2
						3
1,694,784,685	2,003,062,187					4
224,439,413	213,431,469					5
307,382,084	224,666,648					6
3,514,476	466,377					7
20,477,686	18,070,794					8
12,696	12,696					9
						10
						11
1,663,129	32,137,365					12
49,124	21,530,246					13
193,436,946	191,890,475					14
-199,646,971	81,041,949					15
-28,317,629	-7,417,477					16
653,973,341	284,123,530					17
260,867,188	240,319,382					18
-437,912	-439,885					19
						20
						21
35,943,626	16,968,541					22
4,129,102	6,486,186					23
7,904,895	5,756,850					24
2,586,456,003	2,774,470,995					25
426,260,787	364,319,133					26

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 2009/Q4

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)		426,260,787	364,319,133		
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)		32,391,497	31,854,521		
34	(Less) Expenses of Nonutility Operations (417.1)		33,977,093	32,655,625		
35	Nonoperating Rental Income (418)		-258,827	149,118		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	7,130,187			
37	Interest and Dividend Income (419)		1,435,585	6,474,887		
38	Allowance for Other Funds Used During Construction (419.1)		2,712,321	3,073,451		
39	Miscellaneous Nonoperating Income (421)		14,798,563	19,342,253		
40	Gain on Disposition of Property (421.1)		515,258	2,715,535		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		24,747,491	30,954,140		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		138,306	20,502		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		2,550,000	8,585,873		
46	Life Insurance (426.2)					
47	Penalties (426.3)		162,711	-237,797		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		529,125	2,693,263		
49	Other Deductions (426.5)		13,197,506	10,760,658		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		16,577,648	21,822,499		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	872,764	843,148		
53	Income Taxes-Federal (409.2)	262-263	8,119,895	-1,204,387		
54	Income Taxes-Other (409.2)	262-263	619,222	426,315		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	3,702,735	6,180,920		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	14,015,293	7,267,623		
57	Investment Tax Credit Adj.-Net (411.5)		-511,540	-502,112		
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-1,212,217	-1,523,739		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		9,382,060	10,655,380		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		119,078,994	123,540,796		
63	Amort. of Debt Disc. and Expense (428)		3,354,846	2,211,243		
64	Amortization of Loss on Reaquired Debt (428.1)		626,793	1,618,264		
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)		13,051,565	35,021,285		
68	Other Interest Expense (431)		3,495,291	6,729,222		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		10,537,639	25,269,179		
70	Net Interest Charges (Total of lines 62 thru 69)		129,069,850	143,851,631		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		306,572,997	231,122,882		
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)		306,572,997	231,122,882		

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 2009/Q4

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		1,694,275,198	1,466,237,030
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	FIN 157 Adoption, Net of tax $151,732	456		(281,788)
11	EIFT 06-10 Adoption, Net of tax $1,003,509	923		(1,863,660)
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			(2,145,448)
16	Balance Transferred from Income (Account 433 less Account 418.1)		299,442,810	231,122,882
17	Appropriations of Retained Earnings (Acct. 436)			
18	Excess Earnings on Hydro Licensed Projects	215.1	-2,890	(207,158)
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-2,890	(207,158)
23	Dividends Declared-Preferred Stock (Account 437)			
24	Preferred Stock Not Subject to Mandatory Redemption			
25	4.08% Series		-59,548	(59,548)
26	4.20% Series		-95,861	(95,861)
27	4.40% Series		-138,521	(138,521)
28	4.50% Series		-438,140	(438,178)
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		-732,070	(732,108)
30	Dividends Declared-Common Stock (Account 438)			
31	Common Stock		-95,000,000	
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-95,000,000	
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings	JMG Funding	7,130,187	
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		1,905,113,235	1,694,275,198
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
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 2009/Q4

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)		3,689,655	3,686,765
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		3,689,655	3,686,765
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		1,908,802,890	1,697,961,963
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)			
50	Equity in Earnings for Year (Credit) (Account 418.1)		7,130,187	
51	(Less) Dividends Received (Debit)			
52	Transfers to Acct 216.0 (Merger of JMG Funding, LLC)		-7,130,187	
53	Balance-End of Year (Total lines 49 thru 52)			

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 2009/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)	306,572,997	231,122,882
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	331,386,942	243,216,515
5	Amortization of Regulatory Debits and Credits	1,614,005	10,607,119
6	Carrying Costs	-10,697,764	-16,309,219
7	Customer Deposits	-1,923,349	-6,280,339
8	Deferred Income Taxes (Net)	382,793,595	42,717,445
9	Investment Tax Credit Adjustment (Net)	-949,452	-941,997
10	Net (Increase) Decrease in Receivables	-37,011,986	-8,770,334
11	Net (Increase) Decrease in Inventory	-160,038,747	-99,988,539
12	Net (Increase) Decrease in Allowances Inventory	4,481,789	10,556,595
13	Net Increase (Decrease) in Payables and Accrued Expenses	-211,576,321	121,809,478
14	Net (Increase) Decrease in Other Regulatory Assets	-9,234,321	-2,366,713
15	Net Increase (Decrease) in Other Regulatory Liabilities	11,200,615	-11,149,665
16	(Less) Allowance for Other Funds Used During Construction	2,712,321	3,073,451
17	(Less) Undistributed Earnings from Subsidiary Companies	7,130,187	
18	Other (provide details in footnote):	14,780,262	-9,698,937
19	Non-Cash Acquisition of Coal Land Rights		-41,600,000
20	Deferred Property Taxes	-7,109,336	-5,507,115
21	Over/Under Recovery of Fuel, Net	-297,570,318	
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	306,876,103	454,343,725
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-416,597,259	-703,933,962
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	-3,715,822	-5,454,124
30	(Less) Allowance for Other Funds Used During Construction	-2,712,321	-3,073,451
31	Acquired Assets Subject to Lease-back	-1,196,831	-2,032,653
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-418,797,591	-708,347,288
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	38,639,665	8,292,956
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 2009/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	88,007	351,996
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):	-304,220,595	
54	(Increase) Decrease in Other Special Deposits	5,528,454	-1,735,083
55	Notes Receivable from Associated Companies	-438,351,719	
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-1,117,113,779	-701,437,419
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	500,000,000	494,450,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65	Long Term Debt Issuance Costs	-6,224,767	-3,245,752
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):	-2,869,439	11,195,239
68	Notes Payable to Associated Companies		32,339,329
69	Capital Contributions from Parent	550,000,000	
70	Cash Provided by Outside Sources (Total 61 thru 69)	1,040,905,794	534,738,816
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)		-287,225,000
74	Preferred Stock	-678	
75	Common Stock		
76	Other (provide details in footnote):		
77	Notes Payable to Associated Companies	-133,887,073	
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock	-732,070	-732,108
81	Dividends on Common Stock	-95,000,000	
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	811,285,973	246,781,708
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	1,048,297	-311,986
87			
88	Cash and Cash Equivalents at Beginning of Period	935,641	1,247,627
89			
90	Cash and Cash Equivalents at End of period	1,983,938	935,641

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

	2009 Cash Flow Incr / (Decr)	2008 Cash Flow Incr / (Decr)
Utility Plant, Net	$ (7,178,111)	$ (8,036,926)
Property and Investments, Net	(677,506)	(3,119,741)
Margin Deposits	1,712,428	(15,691,883)
Mark-to-Market of Risk Management Contracts	(5,485,614)	(13,838,728)
Prepayments	14,246,372	7,566,649
Accrued Utility Revenues, Net	3,217,215	8,580,358
Miscellaneous Current and Accr Assets	(110)	1,636,045
Unamortized Debt Expense	2,586,203	2,127,305
Other Deferred Debits, Net	4,447,863	5,875,308
Other Comprehensive Income, Net	11,846,793	(2,375,617)
Unamortized Discount/Premium on Long-Term Debt	693,642	716,505
Accumulated Provisions - Misc	1,185,660	(4,137,234)
Current and Accrued Liabilities, Net	(17,720,047)	3,621,470
Other Deferred Credits, Net	5,905,474	7,377,552
Total	**$ 14,780,262**	**$ (9,698,937)**

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

	2009 Cash Flow Incr / (Decr)	2008 Cash Flow Incr / (Decr)
Sale of 1965 Barbour harbor boat to Superior Marine Ways	$ -	$ 305,000
Sale of 29.597 land acres to Stark County Park District	450,000	-
Sale of meters to various associated companies	1,769,914	2,667,105
Sale of transformer to A Line EDS	129,896	535,101
Sale of transformers to various associated companies	4,113,160	2,597,642
Sale of utility equipment to Indiana Michigan Power Company	6,025,663	1,799,893
Sale of Towboats to Chase Equipment Leasing Inc.	25,690,558	-
Proceeds from acquired assets subject to operating lease	460,474	388,215
Total	**$ 38,639,665**	**$ 8,292,956**

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

	2009 Cash Flow Incr / (Decr)	2008 Cash Flow Incr / (Decr)
Purchase of Equity Interest in JMG Funding	(28,220,595)	-
Capital Contribution to JMG Funding	(276,000,000)	-
Total	**$ (304,220,595)**	**$ -**

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

	2009 Cash Flow Incr / (Decr)	2008 Cash Flow Incr / (Decr)
Unamortized Deferred Revenues related to Peabody Coal Contract	$ -	$ 13,312,584
Amortization of Amended Coal Contract Deferred Revenues	(7,309,379)	-
NYMEX contracts related to the Peabody Coal liquidation	-	(3,761,784)
Funds from Coal Contract Liquidations	3,761,784	-
Proceeds from acquired assets subject to capital lease	678,156	1,644,439
Total	**$ (2,869,439)**	**$ 11,195,239**

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

NOTES TO FINANCIAL STATEMENTS

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

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SEE PAGE 123 FOR REQUIRED INFORMATION.

INDEX OF NOTES TO FINANCIAL STATEMENTS

Glossary of Terms for Notes

1. Organization and Summary of Significant Accounting Policies
2. Rate Matters
3. Effects of Regulation
4. Commitments, Guarantees and Contingencies
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8. Fair Value Measurements
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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
AEP or Parent	American Electric Power Company, Inc.
AEP Credit	AEP Credit, Inc., a subsidiary of AEP which factors accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo.
AEP Power Pool	Members are APCo, CSPCo, I&M, KPCo and OPCo. The Pool shares the generation, cost of generation and resultant wholesale off-system sales of the member companies.
AEP System or the 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, a 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.
CSPCo	Columbus Southern Power Company, an AEP electric utility subsidiary.
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. AEPSC acts as the agent.
DETM	Duke Energy Trading and Marketing L.L.C., a risk management counterparty.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company.
ERCOT	Electric Reliability Council of Texas.
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.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.
IGCC	Integrated Gasification Combined Cycle, technology that turns coal into a cleaner-burning gas.

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
Interconnection Agreement	Agreement, dated July 6, 1951, as amended, by and among APCo, CSPCo, 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.
JMG	JMG Funding LP.
KGPCo	Kingsport Power Company, an AEP electric distribution 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 AEP Power Pool transactions to its members.
MMBtu	Million British Thermal Units.
MTM	Mark-to-Market.
MW	Megawatt.
MWH	Megawatthour.
NO_X	Nitrogen oxide.
OCC	Corporation Commission of the State of Oklahoma.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
OTC	Over the counter.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
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.
S&P	Standard and Poor's Ratings Services.
SIA	System Integration Agreement.
SO_2	Sulfur Dioxide.
SPP	Southwest Power Pool.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TA	Transmission Agreement dated April 1, 1984 by and among APCo, CSPCo, I&M, KPCo and OPCo, which allocates costs and benefits in connection with the operation of transmission assets.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
Utility Money Pool	AEP System's Utility Money Pool.
WPCo	Wheeling Power Company, an AEP electric distribution subsidiary.

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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 710,000 retail customers in the northwestern, east central, eastern and southern sections of Ohio. As a member of the AEP Power Pool, OPCo shares in the revenues and the costs of the AEP Power Pool's sales to neighboring utilities and power marketers.

The cost of the AEP Power Pool's generating capacity is allocated among its members based on relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity revenues. The capacity reserve relationship of the AEP Power Pool members changes as generating assets are added, retired or sold and relative peak demand changes. AEP Power Pool members are also compensated for the out-of-pocket costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool. The AEP Power Pool 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.

Under the SIA, AEPSC allocates physical and financial revenues and expenses from 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 and ERCOT 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 existing power pool 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, PSO and SWEPCo related to purchase power and sale activity pursuant to the SIA.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

OPCo's rates are regulated by the FERC and the PUCO. The FERC also regulates OPCo's affiliated transactions, including AEPSC intercompany service billings which are generally at cost, under the 2005 Public Utility Holding Company Act and the Federal Power Act. The FERC also has jurisdiction over the issuances and acquisitions of securities, 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 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 distribution operations and retail rates on a cost basis. The ESP rates in Ohio continue the process of increasing generation/power supply rates over time to approach 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. OPCo's retail transmission rates are based on the FERC's Open Access Transmission Tariff (OATT) rates 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.

The FERC issued Order 715, "Revisions to Forms, Statements and Reporting Requirements for Electric Utilities and Licensees" in September 2008. The order amends the FERC's reporting requirements for public utilities associated with the FERC Form 1 and the FERC Form 3-Q. The revised reporting requirements are intended to enhance the FERC's and customers' review of formula rates, permit a better understanding of non-power goods and services transactions with affiliates and provide additional detail of revenues not previously specified in the FERC Form 1. The new rule took effect January 1, 2009.

Both the FERC and state regulatory commissions are permitted to review and audit the books and records of any company within a public utility holding company system.

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 GAAP include:

- 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 accounting for transactions with JMG Funding LP through December 15, 2009 as a nonaffiliated company rather than consolidating the entity in accordance with the accounting guidance for "Variable Interest Entities."
- The classification of accrued non-ARO asset removal costs as accumulated depreciation rather than regulatory liabilities.
- The classification of capital lease payments as operating activities instead of financing activities.
- The classification of change in emission allowances held for speculation as investing activities instead of operating activities.
- The classification of gains/losses from disposition of allowances as utility operating expenses rather than as operating revenues.
- The classification of PJM hourly activity for physical transactions as purchases and sales instead of net sales.
- The classification of noncurrent tax liabilities related to the accounting guidance for "Uncertainty in Income Taxes" as a current liability rather than a noncurrent liability.
- The classification of regulatory assets and liabilities related to the accounting guidance for "Accounting for Income Taxes" as separate assets and liabilities rather than as a single amount.
- The presentation of capital leased assets and their associated accumulated amortization as a single amount instead of as separate amounts.
- The classification of factored accounts receivable expense as a nonoperating expense instead of as an operating expense.
- The classification of certain nonoperating revenues as miscellaneous nonoperating income instead of as operating revenue.
- The classification of income tax expense on Net Utility Operating Income and on Net Other Income and Deductions instead of as a single net income tax.
- 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 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 (future revenue reductions or refunds) to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues and income with its passage to customers through the reduction of regulated revenues. Due to the passage of legislation requiring restructuring and a transition to customer choice and market-based rates, OPCo discontinued the application of "Regulated Operations" accounting treatment for the generation portion of its business.

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, 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 Statement of Cash Flows include Cash, Working Fund and Temporary Cash Investments on the Comparative Balance Sheet with original maturities of three months or less.

Supplementary Information

	2009	2008
For the Year Ended December 31,	**(in thousands)**	
Cash Was Paid (Received) for:		
Interest (Net of Capitalized Amounts)	$ 121,937	$ 115,330
Income Taxes (Net of Refunds)	(62,704)	100,430
Noncash Acquisitions Under Capital Leases	2,383	3,910
Noncash Acquisitions of Coal Land Rights	-	41,600
At December 31,		
Noncash Construction Expenditures Included in Accounts Payable	29,929	33,177
Revenue Refund Included in Accounts Payable	-	62,045

Special Deposits

Special Deposits include funds held by trustees primarily for margin deposits for risk management activities and environmental construction expenditures.

Inventory

Fossil fuel inventories are generally carried at average cost. Effective January 1, 2009, with the implementation of the FAC in Ohio, OPCo applied "Regulated Operations" accounting guidance for the fuel operations portion of its business and changed its inventory valuation method from lower of average cost or market to average cost. The change had no impact on OPCo's inventory valuation as of January 1, 2009. 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, an estimate of the revenues for energy delivered since the last billing.

AEP Credit factors accounts receivable, excluding receivables from risk management activities, through purchase agreements with OPCo.

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, 2009.

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 provision for credit loss has been made in the financial statements.

Emission Allowances

OPCo records emission allowances at cost, including the annual SO_2 and NO_x emission allowance entitlements received at no cost from the Federal EPA. OPCo follows the inventory model for these allowances. These 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 sale 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

Electric utility property, plant and equipment are stated at original purchase cost. Property, plant and equipment of nonregulated operations and equity investments 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. Additions, major replacements and betterments are added to the plant accounts. Normal and routine retirements from the plant accounts, net of salvage, are charged to accumulated depreciation under the group composite method of 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. 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. For the nonregulated generation assets, a gain or loss would be recorded if the retirement is not considered an interim routine replacement. The depreciation rates that are established for the generating plants 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 for cost-based rate-regulated operations and charged to expense for nonregulated operations. The costs of labor, materials and overhead incurred to operate and maintain the 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 the 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.

Investment in Subsidiary Companies

OPCo has a 50% interest in two jointly owned companies. The investments are included in Investment in Subsidiary Companies and were $734,000 at both December 31, 2009 and 2008. 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 the Statement of Income’s operating expense account.

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 in Ohio, 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, 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 that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability.

For commercial activities, exchange traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified as Level 1. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, as well as exchange traded 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 non-binding 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. Long-dated and illiquid complex or structured transactions and FTRs can introduce the need for internally developed modeling inputs based upon extrapolations and assumptions of observable market data to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized as Level 3.

AEP utilizes its trustee's external pricing service in its estimate of 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 investment managers perform their 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 plans. Equities are classified as Level 1 holdings if they are actively traded on exchanges. Fixed income securities do not trade on an exchange and do not have an official closing price. Pricing vendors calculate bond valuations using financial models and matrices. Fixed income securities are typically classified as Level 2 holdings because their valuation inputs are based on observable market data. Observable inputs used for valuing fixed income securities are benchmark yields, reported trades, broker/dealer quotes, issuer spreads, two-sided markets, benchmark securities, bids, offers, reference data, and economic events. 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 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. Beginning in 2009, OPCo's fuel cost over-recoveries (the excess of fuel revenues billed to customers over applicable fuel costs incurred) are deferred as regulatory liabilities and under-recoveries (the excess of applicable fuel costs incurred over fuel revenues billed to customers) are 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 records a provision for estimated refunds to recognize these probable outcomes. Prior to 2009, changes in fuel costs impacted OPCo's earnings.

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 sheet. 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.

Traditional 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 in the financial statements 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. These power sales and purchases are reported on an hourly net basis. In hours where the AEP East companies are required to purchase more power than they sold into PJM to cover retail and wholesale customer obligations, OPCo's share of these amounts are reported in Operation Expenses. In hours where the AEP East companies sell more power than they purchased from PJM to cover retail and wholesale customer obligations, OPCo's share of these amounts are reported in Operating Revenues. Other RTOs do not function in the same manner as PJM. They function as balancing organizations and not as exchanges.

Physical energy purchases, including those from RTOs, that are identified as non-trading, but excluding PJM purchases described in the preceding paragraph, are accounted for on a gross basis in Operation Expenses on the statements of income.

In general, OPCo records expenses upon receipt of purchased electricity and when expenses are incurred, with the exception of certain power purchase contracts that are derivatives and accounted for using MTM accounting.

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 and the buying and selling of financial energy contracts which include exchange traded futures and options, and over-the-counter options and swaps. 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 on its Statements of Income. For OPCo, the 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 on the Statements of Income.

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. For OPCo, the ineffective portion of the gain or loss is recognized in revenues or expense in the financial statements immediately. See "Accounting for Cash Flow Hedging Strategies" section of Note 7.

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 agents 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.

Debt and Preferred Stock

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 Interest Charges.

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. The net amortization expense is included in Interest Charges.

Where reflected in rates, redemption premiums paid to reacquire preferred stock are included in paid-in capital and amortized to retained earnings commensurate with their recovery in rates. The excess of par value over costs of preferred stock reacquired is credited to paid-in capital and reclassified to retained earnings upon the redemption of the entire preferred stock series.

Investments Held in Trust for Future Liabilities

AEP has several trust funds with significant investments intended to provide for future payments of pension and OPEB benefits, nuclear decommissioning and spent nuclear fuel disposal. All of the trust funds' investments are diversified and managed in compliance with all laws and regulations. The investment strategy for trust funds is to use a diversified portfolio of investments to achieve an acceptable rate of return while managing the interest rate sensitivity of the assets relative to the associated liabilities. To minimize investment risk, the trust funds are broadly diversified among classes of assets, investment strategies and investment managers. Management regularly reviews the actual asset allocation and periodically rebalances the investments to targeted allocation 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 target asset allocation and allocation ranges are as follows:

Pension Plan Assets	Minimum	Target	Maximum
Domestic Equity	30.0%	35.0%	40.0%
International and Global Equity	10.0%	15.0%	20.0%
Fixed Income	35.0%	39.0%	45.0%
Real Estate	4.0%	5.0%	6.0%
Other Investments	1.0%	5.0%	7.0%
Cash	0.5%	1.0%	3.0%

OPEB Plans Assets	Minimum	Target	Maximum
Equity	61.0%	66.0%	71.0%
Fixed Income	29.0%	33.0%	37.0%
Cash	1.0%	1.0%	4.0%

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.
- Individual stock must be less 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 one issuer
- 20% in non-US dollar denominated
- 5% private placements
- 5% 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 six 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 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.

Revised Depreciation Rates

Effective January 1, 2009, OPCo revised book depreciation rates for generating plants consistent with a recently completed depreciation study. OPCo's overall higher depreciation rates primarily related to shortened depreciable lives for certain generating facilities. In comparing 2009 and 2008, the change in depreciation rates resulted in a net increase in depreciation expense of $71.1 million.

Subsequent Events

The March 2010 passage of health care legislation will require several changes to AEP's benefit plans and the related impact on taxes. A change in tax treatment for OPEB deductions related to Medicare Part D reimbursement may unfavorably impact 2010 earnings. Management is currently evaluating the new legislation and its effects on net income, cash flows and financial condition.

2. RATE MATTERS

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

Ohio Electric Security Plan Filings

The PUCO issued an order in March 2009 that modified and approved OPCo's ESP that established rates at the start of the April 2009 billing cycle. The ESP is in effect through 2011. The order also limits rate increases for OPCo to 8% in 2009, 7% in 2010 and 8% in 2011. Some rate components and increases are exempt from these limitations. OPCo collected the 2009 annualized revenue increase over the last nine months of 2009.

The order provides a FAC for the three-year period of the ESP. The FAC increase will be phased in to avoid having the resultant rate increases exceed the ordered annual caps described above. The FAC increase is subject to quarterly true-ups, annual accounting audits and prudence reviews. The order allows OPCo to defer any unrecovered FAC costs resulting from the annual caps and to accrue associated carrying charges at OPCo's weighted average cost of capital. The deferred FAC regulatory asset balance at the end of the three-year ESP period will be recovered through a non-bypassable surcharge over the period 2012 through 2018.

Discussed below are the outstanding uncertainties related to the ESP order:

The Ohio Consumers' Counsel filed a notice of appeal with the Supreme Court of Ohio raising several issues including the alleged retroactive rates, recovery of carrying charges on certain environmental investments, Provider of Last Resort (POLR) charges and the decision not to offset rates by off-system sales margins.

The Industrial Energy Users-Ohio group filed a notice of appeal with the Supreme Court of Ohio challenging other components of the ESP order including the POLR charge, the distribution riders for gridSMART^{SM} and enhanced reliability, the PUCO's conclusion and supporting evaluation that the modified ESPs are more favorable than the expected results of a market rate offer, the unbundling of the fuel and non-fuel generation rate components, the scope and design of the fuel adjustment clause and the approval of the plan after the 150-day statutory deadline. A decision from the Supreme Court of Ohio is still pending.

In 2009, the PUCO convened a workshop to determine the methodology for the Significantly Excessive Earnings Test (SEET). The SEET requires the PUCO to determine, following the end of each year of the ESP, if rate adjustments included in the ESP resulted in significantly excessive earnings. If the rate adjustments, in the aggregate, result in significantly excessive earnings, the excess amount would be returned to customers. The PUCO staff recommended that the SEET be calculated on an individual company basis and not on a combined CSPCo/OPCo basis and that off-system sales margins be included in the earnings test. It is unclear at this time whether the FAC phase-in deferral credits will be included in the earnings test. Management believes that OPCo should not be required to refund unrecovered FAC regulatory assets. The PUCO's decision on the SEET methodology is not expected to be finalized until a SEET filing is made by OPCo in 2010 related to 2009 earnings and the PUCO issues an order thereon. As a result, OPCo is unable to determine whether they will be required to return any of its ESP revenues to customers.

The following uncertainties were resolved in 2009:

Prior to the appeals discussed above, certain intervenors filed appeals of the ESP order with the Supreme Court of Ohio. One of the intervenors asked the court to stay, pending the outcome of its appeal, a portion of the authorized ESP rates which the intervenor characterized as being retroactive. The Supreme Court of Ohio denied the intervenor's request for a stay and granted motions to dismiss both appeals.

The Industrial Energy Users-Ohio group filed a complaint for writ of prohibition with the Supreme Court of Ohio requesting the Court to prohibit OPCo from billing and collecting any ESP rate increases because they assert that the PUCO's statutory jurisdiction over OPCo's ESP application ended on December 28, 2008. OPCo filed a motion to dismiss the complaint for writ of prohibition. In January 2010, the Supreme Court of Ohio granted the motion to dismiss.

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

Ohio IGCC Plant

In March 2005, CSPCo and OPCo filed a joint application with the PUCO seeking authority to recover costs of building and operating an IGCC power plant. CSPCo and OPCo each collected $12 million in pre-construction costs authorized in a June 2006 PUCO order and incurred $11 million in pre-construction costs. As a result, CSPCo and OPCo each established a net regulatory liability of approximately $1 million. The order also provided that if CSPCo and OPCo have not commenced a continuous course of construction of the proposed IGCC plant before June 2011, all pre-construction costs that may be utilized in projects at other sites must be refunded to Ohio ratepayers with interest. Intervenors have filed motions with the PUCO requesting all pre-construction costs be refunded to Ohio ratepayers with interest.

CSPCo and OPCo will not start construction of an IGCC plant until existing statutory barriers are addressed and sufficient assurance of regulatory cost recovery exists. Management cannot predict the outcome of the cost recovery litigation concerning the Ohio IGCC plant or what effect, if any, the litigation will have on future net income and cash flows. However, if CSPCo and OPCo were required to refund the $24 million collected and the costs incurred were not recoverable in another jurisdiction, it would reduce future net income and cash flows.

Ormet

Interim Arrangement

CSPCo, 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 effective from January 2009 through September 2009. In January 2009, the PUCO approved the application. In March 2009, the PUCO approved a FAC in the ESP filings. The approval of the FAC, together with the PUCO approval of the interim arrangement, provided the basis to record regulatory assets for the difference between the approved market price and the rate paid by Ormet. In November 2009, CSPCo and OPCo requested that the PUCO approve recovery of the cumulative balance of the unrecovered FAC deferrals under the interim agreement, plus a weighted average cost of capital carrying charge. As of December 31, 2009, OPCo had $34 million of recorded regulatory assets related to the interim arrangement.

In the ESP proceeding, intervenors requested that OPCo be required to refund this regulatory asset and requested that the PUCO prevent OPCo from collecting these revenues in the future. CSPCo and OPCo filed a response noting that these amounts have not been collected and, in fact, are recorded as regulatory assets with PUCO authorization, pending future authorization for recovery. The PUCO did not take any action on this request in the ESP proceeding. The intervenors raised the issue again in response to CSPCo's and OPCo's November 2009 filing to approve recovery of the cumulative balance of the unrecovered FAC regulatory assets under the interim agreement. If OPCo is not ultimately permitted to recover its under-recovery deferrals under the interim arrangement, it would reduce future net income and cash flows.

Special Arrangement

In 2009, Ormet filed an application with the PUCO for approval of a proposed 10-year power contract under which Ormet would pay varying amounts based on certain conditions, including the price of aluminum and its level of production. The difference between the amounts paid by Ormet and the otherwise applicable PUCO ESP tariff rate would be either collected from or refunded to OPCo's retail customers. The PUCO approved the power contract through 2018 with several modifications, including maximum discounts. The PUCO authorized OPCo to record an Economic Development Rider (EDR) regulatory asset in an amount equal to the difference between the ESP tariff rate and the rate paid by Ormet. In addition, the PUCO ordered OPCo to credit all Ormet-related POLR charges to reduce the EDR under-recovery regulatory asset amounts that OPCo would otherwise recover. The new long-term power contract became effective in September 2009, at which point OPCo began recording a regulatory asset for the unrecovered amounts less Ormet-related POLR revenues. In November 2009, OPCo appealed the POLR issue to the Supreme Court of Ohio. If the appeal is successful, it would increase the revenues collected under the EDR.

In November 2009, OPCo requested the PUCO to approve recovery of the 2009 under-recovery deferral under the Ormet special arrangement and the projected 2010 deferral as a part of the EDR. In January 2010, the PUCO approved OPCo's request. As of December 31, 2009, OPCo had $2 million recorded as an EDR regulatory asset under the Ormet long-term contract. Management cannot predict Ormet's on-going electric consumption levels, the price of aluminum, and/or the amount that OPCo will defer for future recovery through the EDR. If OPCo is not ultimately permitted to recover their deferrals, it would reduce future net income and cash flows.

Regional Transmission Rate Proceedings at the FERC

Seams Elimination Cost Allocation (SECA) Revenue Subject to Refund

In 2004, AEP eliminated transaction-based through-and-out transmission service (T&O) charges in accordance with FERC orders and collected, at the FERC's direction, load-based charges, referred to as RTO SECA, to partially mitigate the loss of T&O revenues on a temporary basis through March 2006. Intervenors objected to the temporary SECA rates. 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 from 2004 through 2006 when the SECA rates terminated leaving the AEP East companies and ultimately their internal load retail customers to make up the shortfall in revenues. OPCo's portion of recognized gross SECA revenues is $53.3 million.

In 2006, a FERC Administrative Law Judge (ALJ) issued an initial decision finding that the rate design for the recovery of SECA charges was flawed and that a large portion of the "lost revenues" reflected in the SECA rates should not have been recoverable. The ALJ found that the SECA rates charged were unfair, unjust and discriminatory and that new compliance filings and refunds should be made. The ALJ also found that any unpaid SECA rates must be paid in the recommended reduced amount.

AEP filed briefs jointly with other affected companies noting exceptions to the ALJ's initial decision and asking the FERC to reverse the decision. Management believes that the FERC should reject the ALJ's initial decision because it contradicts prior related FERC decisions, which are presently subject to rehearing. Furthermore, management believes the ALJ's findings on key issues are largely without merit. AEP and SECA ratepayers have been engaged in settlement discussions in an effort to settle the SECA issue. However, if the ALJ's initial decision is upheld in its entirety, it could result in a refund of a portion or all of the unsettled SECA revenues. In December 2009, several parties filed a motion with the U.S. Court of Appeals to force the FERC to resolve the SECA issue.

The AEP East companies provided reserves for net refunds for SECA settlements totaling $44 million applicable to the $220 million of SECA revenues collected. OPCo's portion of the provision is $10.7 million.

Through 2009, settlements approved by the FERC consumed $10 million of the reserve for refunds applicable to $112 million of SECA revenue. The balance in the reserve for future settlements as of December 31, 2009 was $34 million. As of December 31, 2009, there were no in-process settlements. OPCo's reserve balance at December 31, 2009 was $8.2 million.

Based on settlement experience and the expectation that most of the unsettled SECA revenues will be settled, management believes that the available reserve of $34 million is adequate to settle the remaining $108 million of contested SECA revenues. Management cannot predict the ultimate outcome of future settlement discussions or future FERC proceedings or court appeals. However, if the FERC adopts the ALJ's decision and/or AEP cannot settle all of the remaining unsettled claims within the remaining amount reserved for refund, it would reduce future net income and cash flows.

Allocation of Off-system Sales Margins

The OCC filed a complaint at the FERC alleging that AEP inappropriately allocated off-system sales margins between the AEP East companies and the AEP West companies and did not properly allocate off-system sales margins within the AEP West companies.

In 2008, the FERC issued a final order concluding that AEP inappropriately deviated from off-system sales margin allocation methods in the SIA and the CSW Operating Agreement for the period June 2000 through March 2006. The FERC ordered AEP to recalculate and reallocate the off-system sales margins in compliance with the SIA and to have the AEP East companies issue refunds to the AEP West companies. Although the FERC determined that AEP deviated from the CSW Operating Agreement, the FERC determined that the allocation methodology was reasonable. The FERC ordered AEP to submit a revised CSW Operating Agreement for the period June 2000 to March 2006. AEP filed a motion for rehearing and a revised CSW Operating Agreement for the period June 2000 to March 2006. In 2009, AEP made a compliance filing with the FERC and the AEP East companies refunded approximately $250 million to the AEP West companies. In February 2010, the FERC denied AEP's motion for rehearing.

Modification of the Transmission Agreement (TA)

APCo, CSPCo, I&M, KPCo and OPCo are parties to the TA that provides for a sharing of the cost of transmission lines operated at 138-kV and above and transmission stations containing extra-high voltage facilities. AEPSC, on behalf of the parties to the TA, filed with the FERC a request to modify the TA. Under the proposed amendments, KGPCo and WPCo will be added as parties to the TA. In addition, the amendments would provide for the allocation of PJM transmission costs on the basis of the TA parties' 12-month coincident peak and reimburse transmission revenues based on individual cost of service instead of the MLR method used in the present TA. AEPSC requested the effective date to be the first day of the month following a final non-appealable FERC order. The delayed effective date was approved by the FERC when the FERC accepted the new TA for filing. Settlement discussions are in progress. Management is unable to predict the regulatory lag effect it will experience and its effect on future net income and cash flows due to timing of the implementation by various state regulators of the FERC's new approved TA.

PJM/MISO Market Flow Calculation Errors

During 2009, an analysis conducted by MISO and PJM discovered several instances of unaccounted for power flows on numerous coordinated flowgates. These flows affected the settlement data for congestion revenues and expenses and date back to the start of the MISO market in 2005. PJM has provided MISO an initial analysis of amounts they believe they owe MISO. MISO is disputing PJM's methodology. The FERC is scheduling settlement discussions to resolve the claims. If the FERC approves a settlement above the amount the AEP East companies have recognized related to their portions of PJM's additional costs, it could reduce net income and cash flows.

PJM Transmission Formula Rate Filing

AEP filed an application with the FERC to increase its open access transmission tariff (OATT) rates for wholesale transmission service within PJM. The filing seeks to implement a formula rate allowing annual adjustments reflecting future changes in the AEP East companies' cost of service. The FERC issued an order conditionally accepting AEP's proposed formula rate, subject to a compliance filing, established a settlement proceeding with an Administrative Law Judge and delayed the requested October 2008 effective date for five months. AEP filed the required compliance filing and began settlement discussions with the intervenors and FERC staff. The settlement discussions are currently ongoing.

The requested $63 million increase began in March 2009. Approximately $8 million of the increase will be collected from nonaffiliated customers within PJM. The remaining $55 million requested would be billed to the AEP East companies but would be offset by compensation from PJM for use of the AEP East companies' transmission facilities so that retail rates for jurisdictions other than Ohio were not directly affected. Retail rates for OPCo would be increased on an annual basis through the transmission cost recovery rider (TCRR) mechanism by approximately $13 million. The TCRR includes a true-up mechanism so OPCo's net income will not be adversely affected by a FERC-ordered transmission rate increase.

The first annual update of the formula rate was filed with the FERC which reflected transmission service revenue requirements of an additional $32 million on an annualized basis, effective for service as of July 2009. Approximately $4 million of the increase will be collected from nonaffiliated customers within PJM. Retail rates for OPCo would be increased through the TCRR mechanism by approximately $7 million.

Under the formula, the second annual update will be filed effective July 2010 and each year thereafter. Also, beginning with the July 2010 update, the rates each year will include an adjustment to true-up the prior year's collections to the actual costs for the prior year. Management is unable to predict the outcome of the settlement discussions or any further proceedings that might be necessary if settlement discussions are not successful.

Transmission Agreement (TA)

Certain transmission facilities placed in service in 1998 were inadvertently excluded from the AEP East companies' TA calculation prior to January 2009. The excluded equipment was the Inez Station which had been determined as eligible equipment for inclusion in the TA in 1995 by the AEP TA transmission committee. The amount involved was $7 million annually. Management does not believe that it is probable that a material retroactive rate adjustment will result from the omission. However, if a retroactive adjustment is required, OPCo could experience adverse effects on future net income, cash flows and financial condition.

3. EFFECTS OF REGULATION

Regulatory assets and liabilities are comprised of the following items:

	December 31, 2009	December 31, 2008	Remaining Recovery Period
Regulatory Assets:	(in thousands)		
Regulatory assets not yet being recovered. Recovery method and timing to be determined in future proceedings:			
Regulatory Assets Currently Earning a Return			
Customer Choice Deferrals (a)	$ 28,330	$ 27,707	
Line Extension Carrying Costs (a)	16,278	11,341	
Storm Related Costs (a)	9,794	10,100	
Regulatory Assets Currently Not Earning a Return			
Peak Demand Reduction/Energy Efficiency (a)	4,007	-	
Total Regulatory Assets Not Yet Being Recovered	58,409	49,148	
Regulatory assets being recovered:			
Regulatory Assets Currently Earning a Return			
Fuel Adjustment Clause	303,550	-	3 to 9 years
Economic Development Rider	1,633	-	1 year
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	188,149	203,326	10 to 14 years
Income Taxes Assets	172,452	174,876	20 years
Postemployment Benefits	6,062	4,453	5 years
Total Regulatory Assets Being Recovered	671,846	382,655	
Other	8,382	13,434	various
Total FERC Account 182.3 Regulatory Assets	$ 738,637	$ 445,237	
Unamortized Loss on Reacquired Debt (b)	$ 7,871	$ 8,497	29 years

	December 31, 2009	December 31, 2008	Remaining Refund Period
Regulatory Liabilities:	(in thousands)		
Regulatory liabilities being paid:			
Regulatory Liabilities Currently Paying a Return			
Transmission Cost Recovery Rider	$ 10,003	$ -	2 years
Regulatory Liabilities Currently Not Paying a Return			
Income Tax Liabilities	3,603	4,519	20 years
Unrealized Gain on Forward Commitments	-	4,319	
Total Regulatory Liabilities Being Paid	13,606	8,838	
Other	3,763	3,143	various
Total FERC Account 254 Liabilities	$ 17,369	$ 11,981	
Deferred Investment Tax Credits (b)	$ 1,967	$ 2,917	10 years

(a) Authorization to establish regulatory asset received from the PUCO.
(b) Recorded in an account other than regulatory asset or liability on the balance sheet.

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 adverse 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. 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 at December 31, 2009:

Contractual Commitments	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 911.5	$ 1,449.6	$ 849.4	$ 3,180.7	$ 6,391.2
Energy and Capacity Purchase Contracts (b)	4.1	3.7	-	-	7.8
Construction Contracts for Capital Assets (c)	28.3	63.3	33.9	-	125.5
Total	$ 943.9	$ 1,516.6	$ 883.3	$ 3,180.7	$ 6,524.5

(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 that are contractual commitments. Actual payments are dependent upon and may vary significantly based upon the decision to build, regulatory approval schedules, timing and escalation of project 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 and certain other companies in the AEP System have a $627 million 3-year credit agreement. As of December 31, 2009, $166.9 million of LOCs were issued under the 3-year credit agreement to support variable rate Pollution Control Bonds with a maturity of June 2010. OPCo and certain other companies in the AEP System had a $350 million 364-day credit agreement that expired in April 2009.

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. There are no material liabilities recorded for any indemnifications.

OPCo, along with the other AEP East companies, PSO and SWEPCo are jointly and severally liable for activity conducted by AEPSC on behalf of the AEP East companies, PSO and SWEPCo related to power purchase and sale activity conducted pursuant to the SIA.

Lease Obligations

OPCo leases certain equipment under master lease agreements. See "Master Lease Agreements" section of Note 10 for disclosure of lease residual value guarantees.

ENVIRONMENTAL CONTINGENCIES

Carbon Dioxide Public Nuisance Claims

In 2004, eight states and the City of New York filed an action in Federal District Court for the Southern District of New York against AEP, AEPSC, Cinergy Corp, Xcel Energy, Southern Company and Tennessee Valley Authority. The Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint against the same defendants. The actions allege that CO_2 emissions from the defendants' power plants constitute a public nuisance under federal common law due to impacts of global warming and sought injunctive relief in the form of specific emission reduction commitments from the defendants. The trial court dismissed the lawsuits.

In September 2009, the Second Circuit Court of Appeals issued a ruling on appeal remanding the cases to the Federal District Court for the Southern District of New York. The Second Circuit held that the issues of climate change and global warming do not raise political questions and that Congress' refusal to regulate CO_2 emissions does not mean that plaintiffs must wait for an initial policy determination by Congress or the President's administration to secure the relief sought in their complaints. The court stated that Congress could enact comprehensive legislation to regulate CO_2 emissions or that the Federal EPA could regulate CO_2 emissions under existing CAA authorities and that either of these actions could override any decision made by the district court under federal common law. The Second Circuit did not rule on whether the plaintiffs could proceed with their state common law nuisance claims. In November 2009, the defendants filed for rehearing.

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. OPCo was initially dismissed from this case without prejudice, but is named as a defendant in a pending fourth amended complaint.

Management believes the actions are without merit and intends to continue to defend against the claims.

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. Management believes the action is without merit and intends to defend against the claims.

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 (PCBs) 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. At December 31, 2009, OPCo is named a Potentially Responsible Party (PRP) for three sites by the Federal EPA. There are two additional sites for which OPCo has 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.

Defective Environmental Equipment

As part of the AEP System's continuing environmental investment program, management chose to retrofit wet flue gas desulfurization systems on units utilizing the jet bubbling reactor (JBR) technology. The following plants have been scheduled for the installation of the JBR technology or are currently utilizing JBR retrofits:

Plant Name	Plant Owners	JBRs Scheduled for Installation
Cardinal	OPCo/ Buckeye Power, Inc.	3
Muskingum River (a)	OPCo	1

(a) Contracts for the Muskingum River project have been temporarily suspended during the early development stage of the project.

The retrofits on two of the Cardinal Plant units are operational. Due to unexpected operating results, management completed an extensive review of the design and manufacture of the JBR internal components. The review concluded that there are fundamental design deficiencies and that inferior and/or inappropriate materials were selected for the internal fiberglass components. Management initiated discussions with Black & Veatch, the original equipment manufacturer, to develop a repair or replacement corrective action plan. Management intends to pursue contractual and other legal remedies if these issues with Black & Veatch are not resolved. If the AEP System is unsuccessful in obtaining reimbursement for the work required to remedy this situation, the cost of repair or replacement could have an adverse impact on construction costs, net income, cash flows and financial condition.

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 have a material adverse effect on net income, cash flows and financial condition.

FERC Long-term Contracts

In 2002, the FERC held a hearing related to a complaint filed by Nevada Power Company and Sierra Pacific Power Company (the Nevada utilities). The complaint sought to break long-term contracts entered during the 2000 and 2001 California energy price spike which the customers alleged were "high-priced." The complaint alleged that AEP subsidiaries sold power at unjust and unreasonable prices because the market for power was allegedly dysfunctional at the time such contracts were executed. In September 2009, the parties reached a settlement. The settlement payment was made in February 2010.

5. BENEFIT PLANS

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

OPCo participates in an AEP sponsored qualified pension plan and two unfunded nonqualified pension plans. AEP merged two qualified plans at December 31, 2008. A substantial majority of employees are covered by the qualified plan or both the qualified and a nonqualified pension plan. OPCo participates in OPEB plans sponsored by AEP to provide medical and life insurance benefits for retired employees.

OPCo recognizes the obligations associated with defined benefit pension plans and OPEB plans in its balance sheets at fair value under the "Fair Value Measurements and Disclosures" accounting guidance. Additional disclosures about the plans are required by "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 for qualifying benefit costs of regulated operations that for ratemaking purposes are deferred for future recovery.

Adjustment of pretax AOCI is required at the end of each year, for both underfunded and overfunded defined benefit pension and OPEB plans, to an amount 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 and deferred gains result in an AOCI equity addition. The year-end AOCI measure can be volatile based on fluctuating market conditions, investment returns and discount rates.

The following tables provide a reconciliation of the changes in projected benefit obligations and fair value of assets for AEP's plans over the two-year period ending at the plan's measurement date of December 31, 2009, and their funded status as of December 31 of each year:

Projected Plan Obligations, Plan Assets, Funded Status as of December 31, 2009 and 2008

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,		December 31,	
	2009	2008	2009	2008
Change in Projected Benefit Obligation	(in millions)			
Projected Obligation at January 1	$ 4,301	$ 4,109	$ 1,843	$ 1,773
Service Cost	104	100	42	42
Interest Cost	254	249	110	113
Actuarial Loss	290	139	32	2
Benefit Payments	(248)	(296)	(120)	(120)
Participant Contributions	-	-	25	24
Medicare Subsidy	-	-	9	9
Projected Obligation at December 31	$ 4,701	$ 4,301	$ 1,941	$ 1,843
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets at January 1	$ 3,161	$ 4,504	$ 1,018	$ 1,400
Actual Gain (Loss) on Plan Assets	482	(1,054)	235	(368)
Company Contributions	8	7	150	82
Participant Contributions	-	-	25	24
Benefit Payments	(248)	(296)	(120)	(120)
Fair Value of Plan Assets at December 31	$ 3,403	$ 3,161	$ 1,308	$ 1,018
Underfunded Status at December 31	$ (1,298)	$ (1,140)	$ (633)	$ (825)

Actuarial Assumptions for Benefit Obligations

The weighted-average assumptions as of December 31 of each year used in the measurement of AEP's benefit obligations are shown in the following table:

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,		December 31,	
Assumptions	**2009**	**2008**	**2009**	**2008**
Discount Rate	5.60%	6.00%	5.85%	6.10%
Rate of Compensation Increase	4.60% (a)	5.90% (a)	N/A	N/A

(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.

N/A = Not Applicable

To determine a discount rate, AEP uses a duration-based method by constructing a hypothetical portfolio of high quality corporate bonds similar to those included in the Moody's Aa bond index with a duration matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan.

For 2009, the rate of compensation increase assumed varies with the age of the employee, ranging from 3% per year to 11.5% per year, with an average increase of 4.6%.

Amounts Recognized on AEP's Balance Sheets as of December 31, 2009 and 2008

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,		December 31,	
	2009	**2008**	**2009**	**2008**
	(in millions)			
Other Current Liabilities – Accrued Short-term Benefit Liability	$ (10)	$ (9)	$ (4)	$ (4)
Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability	(1,288)	(1,131)	(629)	(821)
Underfunded Status	$ (1,298)	$ (1,140)	$ (633)	$ (825)

Amounts Recognized in AEP's Accumulated Other Comprehensive Income (AOCI) as of December 31, 2009 and 2008

	Pension Plans December 31,		Other Postretirement Benefit Plans December 31,	
	2009	2008	2009	2008
Components	(in millions)			
Net Actuarial Loss	$ 2,096	$ 2,024	$ 546	$ 715
Prior Service Cost	12	13	3	3
Transition Obligation	-	-	43	70
Pretax AOCI	$ 2,108	$ 2,037	$ 592	$ 788
Recorded as				
Regulatory Assets	$ 1,750	$ 1,660	$ 380	$ 502
Deferred Income Taxes	125	132	74	100
Net of Tax AOCI	233	245	138	186
Pretax AOCI	$ 2,108	$ 2,037	$ 592	$ 788

Components of the Change in AEP's Plan Assets and Benefit Obligations Recognized in Pretax AOCI during the years ended December 31, 2009 and 2008 are as follows:

	Pensions Plans Years Ended December 31,		Other Postretirement Benefit Plans Years Ended December 31,	
	2009	2008	2009	2008
Components	(in millions)			
Actuarial Loss (Gain) During the Year	$ 130	$ 1,527	$ (127)	$ 492
Amortization of Actuarial Loss	(59)	(37)	(42)	(9)
Prior Service Credit	-	(1)	-	-
Amortization of Transition Obligation	-	-	(27)	(27)
Total Pretax AOCI Change for the Year	$ 71	$ 1,489	$ (196)	$ 456

Pension and Other Postretirement Plans' Assets

The value of AEP's pension plan's assets increased to $3.4 billion at December 31, 2009 from $3.2 billion at December 31, 2008. The qualified plan paid $240 million in benefits to plan participants during 2009 (nonqualified plans paid $8 million in benefits). The value of the OPEB plans' assets increased to $1.3 billion at December 31, 2009 from $1 billion at December 31, 2008. The OPEB plans paid $120 million in benefits to plan participants during 2009.

The following table presents the classification of pension plan assets within the fair value hierarchy at December 31, 2009:

Major Categories of Plan Assets	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 1,219	$ -	$ -	$ -	$ 1,219	35.8%
International	320	-	-	-	320	9.4%
Real Estate Investment Trusts	87	-	-	-	87	2.6%
Common Collective Trust – International	-	161	-	-	161	4.7%
Subtotal Equities	1,626	161	-	-	1,787	52.5%
Fixed Income:						
United States Government and Agency Securities	-	233	-	-	233	6.9%
Corporate Debt	-	831	-	-	831	24.4%
Foreign Debt	-	171	-	-	171	5.0%
State and Local Government	-	35	-	-	35	1.0%
Other – Asset Backed	-	27	-	-	27	0.8%
Subtotal Fixed Income	-	1,297	-	-	1,297	38.1%
Real Estate	-	-	90	-	90	2.7%
Alternative Investments	-	-	106	-	106	3.1%
Securities Lending	-	173	-	-	173	5.1%
Securities Lending Collateral (a)	-	-	-	(196)	(196)	(5.8)%
Cash and Cash Equivalents (b)	-	116	-	4	120	3.5%
Other – Pending Transactions and Accrued Income (c)	-	-	-	26	26	0.8%
Total	$ 1,626	$ 1,747	$ 196	$ (166)	$ 3,403	100.0%

(a) Amounts in "Other" column primarily represent an obligation to repay cash collateral received as part on the Security Lending Program.
(b) Amounts in "Other" column primarily represent foreign currency holdings.
(c) 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 real estate and alternative investments classified as Level 3 in the fair value hierarchy for the pension assets:

	Real Estate	Alternative Investments	Total Level 3
		(in millions)	
Balance as of January 1, 2009	$ 137	$ 106	$ 243
Actual Return on Plan Assets			
Relating to Assets Still Held as of the Reporting Date	(47)	(14)	(61)
Relating to Assets Sold During the Period	-	1	1
Purchases and Sales	-	13	13
Transfers in and/or out of Level 3	-	-	-
Balance as of December 31, 2009	$ 90	$ 106	$ 196

The following table presents the classification of OPEB plan assets within the fair value hierarchy at December 31, 2009:

Major Categories of Plan Assets	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 343	$ -	$ -	$ -	$ 343	26.2%
International	375	-	-	-	375	28.7%
Common Collective Trust – International	-	93	-	-	93	7.1%
Subtotal Equities	718	93	-	-	811	62.0%
Fixed Income:						
Common Collective Trust – Debt	-	38	-	-	38	2.9%
United States Government and Agency Securities	-	42	-	-	42	3.2%
Corporate Debt	-	141	-	-	141	10.8%
Foreign Debt	-	32	-	-	32	2.4%
State and Local Government	-	6	-	-	6	0.5%
Other – Asset Backed	-	2	-	-	2	0.2%
Subtotal Fixed Income	-	261	-	-	261	20.0%
Trust Owned Life Insurance:						
International Equities	-	75	-	-	75	5.7%
United States Bonds	-	131	-	-	131	10.0%
Cash and Cash Equivalents (a)	7	14	-	1	22	1.7%
Other – Pending Transactions and Accrued Income (b)	-	-	-	8	8	0.6%
Total	$ 725	$ 574	$ -	$ 9	$ 1,308	100.0%

(a) Amounts in “Other” column primarily represent foreign currency holdings.
(b) Amounts in “Other” column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The asset allocations for AEP's plans at the end of 2008 by asset category, were as follows:

	Percentage of Plan Assets at December 31, 2008	
Asset Category	**Pension Plans**	**Other Postretirement Benefit Plans**
Equity Securities	47%	53%
Real Estate	6%	-
Debt Securities	42%	43%
Cash and Cash Equivalents	5%	4%
Total	100%	100%

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 quality, portfolio duration and concentration limits. The guidelines were established to mitigate the risk of loss due to significant concentrations in any investment. AEP monitors the plan to control security diversification and ensure compliance with its investment policy. At December 31, 2009, 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.

Determination of Pension Expense

AEP bases its determination of pension expense or income 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 based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded.

	December 31,	
Accumulated Benefit Obligation	**2009**	**2008**
	(in millions)	
Qualified Pension Plans	$ 4,539	$ 4,119
Nonqualified Pension Plans	90	80
Total	$ 4,629	$ 4,199

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 at December 31, 2009 and 2008 were as follows:

	Underfunded Pension Plans	
	December 31,	
	2009	2008
	(in millions)	
Projected Benefit Obligation	$ 4,701	$ 4,301
Accumulated Benefit Obligation	$ 4,629	$ 4,199
Fair Value of Plan Assets	3,403	3,161
Underfunded Accumulated Benefit Obligation	$ 1,226	$ 1,038

Estimated Future Benefit Payments and Contributions

AEP expects contributions and payments for the pension plans of $160 million and the OPEB plans of $117 million during 2010. The amount for the pension plans is at least the minimum amount required by Employee Retirement Income Security Act of 1974, as amended, plus payment of unfunded nonqualified benefits. For the qualified pension plan, AEP may make additional discretionary contributions to maintain the funded status of the plan. The contribution to the OPEB plans is generally based on the amount of the OPEB plans' periodic benefit costs for accounting purposes as provided for in agreements with state regulatory authorities, plus the additional discretionary contribution of the Medicare subsidy receipts.

The table below reflects the total benefits expected to be paid from the plan or from the employer's assets, including both the employer's share of the benefit cost and the participants' share of the cost, which is funded by participant contributions to the plan. Medicare subsidy receipts are shown in the year of the corresponding benefit payments, even though actual cash receipts are expected early in the following year. 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 AEP's pension benefits and OPEB are as follows:

	Pension Plans	Other Postretirement Benefit Plans	
	Pension Payments	Benefit Payments	Medicare Subsidy Receipts
		(in millions)	
2010	$ 332	$ 119	$ (10)
2011	342	130	(11)
2012	348	139	(13)
2013	355	148	(14)
2014	358	158	(15)
Years 2015 to 2019, in Total	1,871	923	(95)

Components of Net Periodic Benefit Cost

The following table provides the components of AEP's net periodic benefit cost for the plans for the years ended December 31, 2009 and 2008:

	Pension Plans		Other Postretirement Benefit Plans	
	Years Ended December 31,			
	2009	2008	2009	2008
	(in millions)			
Service Cost	$ 104	$ 100	$ 42	$ 42
Interest Cost	254	249	110	113
Expected Return on Plan Assets	(321)	(336)	(80)	(111)
Amortization of Transition Obligation	-	-	27	27
Amortization of Prior Service Cost	-	1	-	-
Amortization of Net Actuarial Loss	59	37	42	9
Net Periodic Benefit Cost	96	51	141	80
Capitalized Portion	(30)	(16)	(44)	(25)
Net Periodic Benefit Cost Recognized as Expense	$ 66	$ 35	$ 97	$ 55

Estimated amounts expected to be amortized to net periodic benefit costs for AEP's plans during 2010 are shown in the following table:

Components	Pension Plans	Other Postretirement Benefit Plans
	(in millions)	
Net Actuarial Loss	$ 99	$ 29
Prior Service Cost	1	-
Transition Obligation	-	27
Total Estimated 2010 Pretax AOCI Amortization	$ 100	$ 56
Expected to be Recorded as		
Regulatory Asset	$ 82	$ 37
Deferred Income Taxes	6	7
Net of Tax AOCI	12	12
Total	$ 100	$ 56

Net Benefit Cost

The following table provides OPCo's net periodic benefit cost for the plans for the years ended December 31, 2009 and 2008:

Pension Plans		Other Postretirement Benefit Plans	
Years Ended December 31,			
2009	2008	2009	2008
(in thousands)			
$ 8,268	$ 1,277	$ 20,557	$ 11,357

Actuarial Assumptions for Net Periodic Benefit Costs

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

	Pension Plans		Other Postretirement Benefit Plans	
	2009	**2008**	**2009**	**2008**
Discount Rate	6.00%	6.00%	6.10%	6.20%
Expected Return on Plan Assets	8.00%	8.00%	7.75%	8.00%
Rate of Compensation Increase	5.90%	5.90%	N/A	N/A

N/A = Not Applicable

The expected return on plan assets for 2009 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	2009	2008
Initial	6.50%	7.00%
Ultimate	5.00%	5.00%
Year Ultimate Reached	2012	2012

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 millions)	
Effect on Total Service and Interest Cost Components of Net Periodic Postretirement Health Care Benefit Cost	$ 20	$ (16)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	217	(180)

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 who are not members of the United Mine Workers of America (UMWA). 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 was 75% of the first 6% of eligible compensation contributed by the employee in 2008. Effective January 1, 2009, the match is 100% of the first 1% of eligible employee contributions and 70% of the next 5% of contributions.

OPCo's cost for contributions to the retirement savings plans was $7.6 million and $7.2 million for the years ended December 31, 2009 and 2008, respectively.

UMWA Benefits

OPCo provides UMWA pension, health and welfare benefits for certain unionized mining employees, retirees and their survivors who meet eligibility requirements. UMWA trustees make final interpretive determinations with regard to all benefits. The pension benefits are administered by UMWA trustees and contributions are made to their trust funds. The health and welfare benefits are administered by OPCo. Benefits are paid from OPCo's general assets. Contributions and benefits paid were not material in 2009 and 2008.

6. BUSINESS SEGMENTS

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

7. 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. These risks are managed using derivative instruments.

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

The strategy surrounding the use of derivative instruments focuses on managing risk exposures, future cash flows and creating value based on open trading positions by utilizing both economic and formal hedging strategies. To accomplish these objectives, AEPSC, on behalf of OPCo, primarily employs risk management contracts including physical forward purchase and sale contracts, financial forward purchase and sale contracts and financial swap instruments. 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 electricity, coal, natural gas, interest rate and to a lesser degree heating oil, 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 long-term commodity derivative positions. For disclosure purposes, such risks are grouped as "Commodity," as these risks are related to energy risk management activities. From time to time, 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 outstanding derivative contracts as of December 31, 2009:

Primary Risk Exposure	Unit of Measure	Volume
Commodity:		(in thousands)
Power	MWHs	112,745
Coal	Tons	23,631
Natural Gas	MMBtus	10,539
Heating Oil and Gasoline	Gallons	838
Interest Rate	USD	$ 13,487

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 electricity, coal, heating oil and natural gas ("Commodity") in order to manage the variable price risk related to the forecasted purchase and sale of these commodities. Management closely 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 gasoline and heating oil derivative contracts in order to mitigate price risk of future fuel purchases. For disclosure purposes, these contracts are included with other hedging activity 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 anticipated borrowings of fixed-rate debt. The anticipated 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 because 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 in 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, 2009 and December 31, 2008 Comparative Balance Sheet, 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,			
2009		2008	
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
(in thousands)			
$ 2,235	$ 19,512	$ 1,522	$ 3,909

The following table represents the gross fair value impact of derivative activity on the Comparative Balance Sheet as of December 31, 2009:

	Risk Management Contracts	Hedging Contracts			
Balance Sheet Location	**Commodity (a)**	**Commodity (a)**	**Interest Rate and Foreign Currency (a)**	**Other (a) (b)**	**Total**
			(in thousands)		
Derivative Instrument Assets	$ 343,243	$ -	$ -	$ (266,434)	$ 76,809
Long-Term Portion of Derivative Instrument Assets	88,064	-	-	(60,061)	28,003
Derivative Instrument Assets – Hedges	-	2,199	-	(957)	1,242
Long-Term Portion of Derivative Instrument Assets – Hedges	-	-	-	-	-
Derivative Instrument Liabilities	322,063	-	-	(287,250)	34,813
Long-Term Portion of Derivative Instrument Liabilities	81,186	-	-	(68,723)	12,463
Derivative Instrument Liabilities – Hedges	-	3,045	-	(957)	2,088
Long-Term Portion of Derivative Instrument Liabilities – Hedges	-	47	-	-	47

(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 represent counterparty netting of risk management and hedging contracts, associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging" and dedesignated risk management contracts.

The table below presents the activity of derivative risk management contracts for the year ended December 31:

Amount of Gain (Loss) Recognized on Risk Management Contracts For the Year Ended December 31, 2009

Location of Gain (Loss)	(in thousands)
Operating Revenues	$ 29,455
Regulatory Liabilities (a)	18,006
Total Gain (Loss) on Risk Management Contracts	$ 47,461

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment recorded as non-current within the balance sheet.

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 Operating 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 Cash Flow Hedging Strategies

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), 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 electricity, coal, heating oil 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 2009 and 2008 OPCo designated commodity derivatives as cash flow hedges.

Beginning in 2009, AEPSC, on behalf of OPCo, executed financial heating oil and gasoline derivative contracts to hedge the price risk of diesel fuel and gasoline purchases. OPCo reclassifies gains and losses on financial fuel 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 2009, OPCo designated cash flow hedging strategies of forecasted fuel purchases. This strategy was not active during 2008.

OPCo reclassifies gains and losses on interest rate derivative hedges related to debt financing from Accumulated Other Comprehensive Income into Interest Charges in those periods in which hedged interest payments occur. During 2009 and 2008, OPCo designated interest rate derivatives as cash flow hedges.

The accumulated gains or losses related to foreign currency hedges are reclassified from Accumulated Other Comprehensive Income on the balance sheets into Depreciation Expense on the statements of income over the depreciable lives of the fixed assets that were designated as the hedged items in qualifying foreign currency hedging relationships. During 2008, OPCo designated foreign currency derivatives as cash flow hedges.

During 2009, OPCo recognized a $6 million gain in Interest Charges related to hedge ineffectiveness on interest rate derivatives designated in cash flow hedge strategies. During 2009 and 2008 hedge ineffectiveness was immaterial or nonexistent for all other hedge strategies disclosed above.

The following tables provides details on designated, effective cash flow hedges included in AOCI on the balance sheets and the reasons for changes in cash flow hedges for the year ended December 31, 2009. All amounts in the following tables are presented net of related income taxes.

Total Accumulated Other Comprehensive Income Activity for Cash Flow Hedges
For the Year Ended December 31, 2009

	Commodity Contracts	Interest Rate and Foreign Currency Contracts	Total Contracts
		(in thousands)	
Beginning Balance in AOCI as of January 1, 2009	$ 1,898	$ 1,752	$ 3,650
Changes in Fair Value Recognized in AOCI	(522)	10,915	10,393
Amount of (Gain) or Loss Reclassified from AOCI to Income Statement/within Balance Sheet:			
Operating Revenues	(4,903)	-	(4,903)
Operation Expenses	3,207	-	3,207
Depreciation Expense	-	4	4
Interest on Long-term Debt	-	(499)	(499)
Utility Plant	(46)	-	(46)
Ending Balance in AOCI as of December 31, 2009	$ (366)	$ 12,172	$ 11,806

OPCo's amount of income reclassified from AOCI to net income during 2008 was $1.5 million.

Cash flow hedges included in Accumulated Other Comprehensive Income on the balance sheets at December 31, 2009 were:

Impact of Cash Flow Hedges on the Balance Sheets
December 31, 2009

Hedging Assets (a)		Hedging Liabilities (a)		AOCI Gain (Loss) Net of Tax	
Commodity	Interest Rate and Foreign Currency	Commodity	Interest Rate and Foreign Currency	Commodity	Interest Rate and Foreign Currency
		(in thousands)			
$ 1,242	$ -	$ (2,088)	$ -	$ (366)	$ 12,172

Expected to be Reclassified to Net Income During the Next Twelve Months		
Commodity	Interest Rate and Foreign Currency	Maximum Term for Exposure to Variability of Future Cash Flows
(in thousands)		(in months)
$ (335)	$ 1,359	14

(a) Hedging assets and hedging liabilities are included in Derivative Instruments Assets – Hedges and 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.

Credit Risk

AEPSC, on behalf of OPCo, limits credit risk in its 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, S&P and current market-based qualitative and quantitative data to assess the financial health of counterparties on an ongoing basis. If an external rating is not available, an internal rating is generated utilizing a quantitative tool developed by Moody's to estimate probability of default that corresponds to an implied external agency credit rating.

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 a limited number of derivative and non-derivative counterparty contracts primarily related to pre-2002 risk management activities and under the tariffs of the RTOs and Independent System Operators (ISOs), OPCo is obligated to post an 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. Management believes that a downgrade below investment grade is unlikely. As of December 31, 2009, the aggregate value of such contracts was $1.3 million. OPCo would have been required to post $5.0 million of collateral at December 31, 2009 if the credit ratings had declined below investment grade of which $4.7 million was attributable to RTO and ISO activities. As of December 31, 2009, OPCo was not required to post any cash collateral.

In addition, a majority of 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 under borrowed debt 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. Management believes that a non-performance event under these provisions is unlikely. As of December 31, 2009, OPCo's share of the fair value of derivative liabilities subject to cross-default provisions totaled $91.4 million prior to consideration of contractual netting arrangements. This exposure has been reduced by cash collateral posted of $1.8 million. If a cross-default provision would have been triggered, a settlement of up to $19.6 million would be required after considering the contractual netting arrangements.

8. FAIR VALUE MEASUREMENTS

Fair Value Measurements of Long-term Debt

The fair values of Long-term Debt are based on quoted market prices, without credit enhancements, for the same or similar issues and the current interest rates offered for instruments with similar maturities. 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 at December 31, 2009 and 2008 are summarized in the following table:

December 31,			
2009		2008	
Book Value	Fair Value	Book Value	Fair Value
(in thousands)			
$ 3,242,505	$ 3,380,084	$ 2,704,746	$ 2,621,508

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, OPCo's financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2009 and 2008. 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 as of December 31, 2009

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Special Deposits (d) (e)	$ 1,075	$ -	$ -	$ 24	$ 1,099
Derivative Instrument Assets					
Risk Management Contracts (a)	1,383	332,904	7,644	(270,272)	71,659
Dedesignated Risk Management Contracts (b)	-	-	-	5,150	5,150
Total Derivative Instrument Assets	1,383	332,904	7,644	(265,122)	76,809
Derivative Instrument Assets – Hedges (a)	-	2,199	-	(957)	1,242
Total Assets	$ 2,458	$ 335,103	$ 7,644	$ (266,055)	$ 79,150
Liabilities:					
Derivative Instrument Liabilities					
Risk Management Contracts (a)	$ 1,562	$ 317,114	$ 2,075	$ (287,549)	$ 33,202
DETM Assignment (c)	-	-	-	1,611	1,611
Total Derivative Instrument Liabilities	1,562	317,114	2,075	(285,938)	34,813
Derivative Instrument Liabilities – Hedges (a)	-	3,045	-	(957)	2,088
Total Liabilities	$ 1,562	$ 320,159	$ 2,075	$ (286,895)	$ 36,901

Assets and Liabilities Measured at Fair Value on a Recurring Basis as of December 31, 2008

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Special Deposits (d) (e)	$ 4,197	$ -	$ -	$ 2,431	$ 6,628
Derivative Instrument Assets					
Risk Management Contracts (a)	11,200	575,415	8,364	(515,162)	79,817
Dedesignated Risk Management Contracts (b)	-	-	-	8,941	8,941
Total Derivative Instrument Assets	11,200	575,415	8,364	(506,221)	88,758
Derivative Instrument Assets – Hedges (a)	-	4,614	-	(983)	3,631
Total Assets	$ 15,397	$ 580,029	$ 8,364	$ (504,773)	$ 99,017
Liabilities:					
Derivative Instrument Liabilities					
Risk Management Contracts (a)	$ 13,080	$ 550,278	$ 2,801	$ (517,548)	$ 48,611
DETM Assignment (c)	-	-	-	3,637	3,637
Total Derivative Instrument Liabilities	13,080	550,278	2,801	(513,911)	52,248
Derivative Instrument Liabilities – Hedges (a)	-	1,770	-	(983)	787
Total Liabilities	$ 13,080	$ 552,048	$ 2,801	$ (514,894)	$ 53,035

(a) Amounts in "Other" column primarily represent counterparty netting of risk management and hedging contracts and associated cash collateral under the accounting guidance for "Derivatives and Hedging."

(b) "Dedesignated Risk Management Contracts" are 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.

(c) See "Natural Gas Contracts with DETM" section of Note 12.

(d) Amounts in "Other" column primarily represent cash deposits with third parties. Level 1 amounts primarily represent investments in money market funds.

(e) Other cash deposits are included in Special Deposits on the Comparative Balance Sheet.

The following table sets forth a reconciliation of changes in the fair value of net trading derivatives classified as level 3 in the fair value hierarchy:

	Years Ended December 31, 2009	2008
	(in thousands)	
Balance as of January 1,	$ 5,563	$ (1,607)
Realized (Gain) Loss Included in Net Income (or Changes in Net Assets) (a)(b)	(921)	1,406
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	4,947	2,082
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-	-
Purchases, Issuances and Settlements (c)	(3,683)	-
Transfers in and/or out of Level 3 (d)	(337)	(637)
Changes in Fair Value Allocated to Regulated Jurisdictions (e)	-	4,319
Balance as of December 31,	$ 5,569	$ 5,563

(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 either previously categorized as a higher level for which the inputs to the model became unobservable or assets and liabilities that were previously classified as level 3 for which the lowest significant input became observable during the period.

(e) 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.

9. INCOME TAXES

The details of income taxes as reported are as follows:

	Years Ended December 31, 2009	2008
	(in thousands)	
Charged (Credited) to Operating Expenses, Net:		
Current	$ (227,964)	$ 73,625
Deferred	393,106	43,804
Deferred Investment Tax Credits	(438)	(440)
Total	164,704	116,989
Charged (Credited) to Nonoperating Income, Net:		
Current	8,739	(778)
Deferred	(10,313)	(1,087)
Deferred Investment Tax Credits	(511)	(502)
Total	(2,085)	(2,367)
Total Income Taxes	$ 162,619	$ 114,622

Shown below is a reconciliation of the difference between the amount 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, 2009	2008
	(in thousands)	
Net Income	$ 306,573	$ 231,123
Income Taxes	162,619	114,622
Pretax Income	$ 469,192	$ 345,745
Income Tax on Pretax Income at Statutory Rate (35%)	$ 164,217	$ 121,011
Increase (Decrease) in Income Tax resulting from the following items:		
Depreciation	5,371	4,389
Allowance for Funds Used During Construction	(1,427)	(1,555)
Investment Tax Credits, Net	(949)	(942)
State and Local Income Taxes	4,766	2,102
Other	(9,359)	(10,383)
Total Income Taxes	$ 162,619	$ 114,622
Effective Income Tax Rate	34.7%	33.2%

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

	December 31, 2009	December 31, 2008
	(in thousands)	
Deferred Tax Assets	$ 270,381	$ 322,089
Deferred Tax Liabilities	(1,615,446)	(1,252,261)
Net Deferred Tax Liabilities	$ (1,345,065)	$ (930,172)
Property Related Temporary Differences	$ (1,140,767)	$ (893,504)
Amounts Due from Customers for Future Federal Income Taxes	(53,651)	(55,181)
Deferred State Income Taxes	(88,862)	(49,891)
Deferred Income Taxes on Other Comprehensive Loss	63,785	72,014
Accrued Pensions	3,602	720
Regulatory Assets	(74,769)	(82,044)
Deferred Fuel and Purchased Power	(109,204)	-
All Other, Net	54,801	77,714
Net Deferred Tax Liabilities	$ (1,345,065)	$ (930,172)

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.

OPCo and other AEP subsidiaries are no longer subject to U.S. federal examination for years before 2001. OPCo and other AEP subsidiaries have completed the exam for the years 2001 through 2006 and have issues that are being pursued at the appeals level. The years 2007 and 2008 are currently under examination. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for 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 have a material adverse effect on net income.

OPCo, along with other AEP subsidiaries, files income tax returns in various state and local jurisdictions. These taxing authorities routinely examine the tax returns and 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 the ultimate resolution of these audits will not materially impact net income. With few exceptions, OPCo is no longer subject to state or local income tax examinations by tax authorities for years before 2000.

OPCo sustained federal, state and local net income tax operating losses in 2009 driven primarily by bonus depreciation, a change in tax accounting method related to units of property and other book versus tax temporary differences. As a result, OPCo accrued current federal, state and local income tax benefits in 2009. There is sufficient capacity in prior periods to carry the AEP System's consolidated federal net operating loss back. The preponderance of the state and local jurisdictions do not provide for a net operating loss carry back. It is anticipated that future taxable income will be sufficient to realize the tax benefit. As such, management has determined that a valuation allowance is unnecessary.

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 OPCo's amounts reported for interest expense, interest income and reversal of prior period interest expense:

	Years Ended December 31, 2009	Years Ended December 31, 2008
	(in thousands)	
Interest Expense	$ 2,221	$ 4,093
Interest Income	-	5,755
Reversal of Prior Period Interest Expense	1,495	295

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

	December 31, 2009	December 31, 2008
	(in thousands)	
Accrual for Receipt of Interest	$ 1,339	$ 4,508
Accrual for Payment of Interest and Penalties	4,411	6,320

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

	2009	2008
	(in thousands)	
Balance at January 1,	$ 52,338	$ 51,982
Increase - Tax Positions Taken During a Prior Period	11,970	3,133
Decrease - Tax Positions Taken During a Prior Period	(14,030)	(2,692)
Increase - Tax Positions Taken During the Current Year	890	2,446
Decrease - Tax Positions Taken During the Current Year	-	(835)
Increase - Settlements with Taxing Authorities	-	192
Decrease - Settlements with Taxing Authorities	-	-
Decrease - Lapse of the Applicable Statute of Limitations	(2,355)	(1,888)
Balance at December 31,	$ 48,813	$ 52,338

The total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate was $23.8 million. Management believes that there will be no significant net increase or decrease in unrecognized benefits within 12 months of the reporting date.

Federal Tax Legislation

Several tax bills and other legislation with tax-related sections were enacted in 2008, including the Emergency Economic Stabilization Act of 2008. These tax law changes enacted in 2008 did not materially affect OPCo's net income, cash flows or financial condition.

The Economic Stimulus Act of 2008 provided enhanced expensing provisions for certain assets placed in service in 2008 and a 50% bonus depreciation provision similar to the one in effect in 2003 through 2004 for assets placed in service in 2008. The enacted provisions did not have a material impact on net income or financial condition, but provided OPCo a material favorable cash flow benefit of $37.7 million.

The American Recovery and Reinvestment Act of 2009 provided for several new grant programs and expanded tax credits and an extension of the 50% bonus depreciation provision enacted in the Economic Stimulus Act of 2008. The enacted provisions did not have a material impact on net income or financial condition. However, the bonus depreciation contributed to AEP's 2009 federal net operating tax loss and will result in a future cash flow benefit to its subsidiaries including OPCo.

State Tax Legislation

Under Ohio House Bill 66, enacted in 2005, OPCo reversed deferred state income tax liabilities that were not expected to reverse during a phase-out. The PUCO ordered OPCo to amortize $42 million to income as an offset to power supply contract losses incurred for sales to Ormet and as of December 31, 2008, the regulatory liability was fully amortized.

The Ohio legislation also imposed a new commercial activity tax at a fully phased-in rate of 0.26% on all Ohio gross receipts. The tax is being phased-in over a five-year period that began July 1, 2005. As a result of this tax, expenses of approximately $5 million and $4 million were recorded in 2009 and 2008, respectively.

Michigan Senate Bill 0094 (MBT Act), effective January 1, 2008, provided a comprehensive restructuring of Michigan's principal business tax. The law replaced the Michigan Single Business Tax. The MBT Act is composed of a new tax which will be calculated based upon two components: (a) a business income tax (BIT) imposed at a rate of 4.95% and (b) a modified gross receipts tax (GRT) imposed at a rate of 0.80%, which will collectively be referred to as the BIT/GRT tax calculation. The new law also includes significant credits for engaging in Michigan-based activity.

House Bill 5198 amended the MBT Act to provide for a new deduction on the BIT and GRT tax returns equal to the book-tax basis difference triggered as a result of the enactment of the MBT Act. This state-only temporary difference will be deducted over a 15 year period on the MBT Act tax returns starting in 2015. Management has evaluated the impact of the MBT Act and the application of the MBT Act will not materially affect net income, cash flows or financial condition.

In March 2008, legislation was signed providing for, among other things, a reduction in the West Virginia corporate income tax rate from 8.75% to 8.5% beginning in 2009. The corporate income tax rate could also be reduced to 7.75% in 2012 and 7% in 2013 contingent upon the state government achieving certain minimum levels of shortfall reserve funds. Management has evaluated the impact of the law change and the application of the law change will not materially impact net income, cash flows or financial condition.

10. LEASES

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 in accordance with rate-making treatment for regulated operations. Capital leases for nonregulated property are accounted for as if the assets were owned and financed. The components of rental costs are as follows:

	Years Ended December 31, 2009	2008
	(in thousands)	
Net Lease Expense on Operating Leases	$ 89,681	$ 82,441
Amortization of Capital Leases	4,688	6,369
Interest on Capital Leases	1,284	1,606
Total Lease Rental Costs	$ 95,653	$ 90,416

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

	December 31, 2009	2008
	(in thousands)	
Property, Plant and Equipment Under Capital Leases		
Production	$ 23,018	$ 21,220
Other Property, Plant and Equipment	13,344	24,748
Total Property, Plant and Equipment	36,362	45,968
Accumulated Amortization	16,066	21,490
Net Property, Plant and Equipment Under Capital Leases	$ 20,296	$ 24,478
Obligations Under Capital Leases		
Noncurrent	$ 16,926	$ 19,603
Current	5,756	6,863
Total Obligations Under Capital Leases	$ 22,682	$ 26,466

Future minimum lease payments consisted of the following at December 31, 2009:

	Capital Leases	Noncancelable Operating Leases
	(in thousands)	
2010	$ 4,453	$ 28,683
2011	4,150	39,904
2012	2,099	21,232
2013	2,585	20,223
2014	1,937	19,002
Later Years	16,899	86,424
Total Future Minimum Lease Payments	32,123	$ 215,468
Less Estimated Interest Element	9,441	
Estimated Present Value of Future Minimum Lease Payments	$ 22,682	

Master Lease Agreements

OPCo leases certain equipment under master lease agreements. GE Capital Commercial Inc. (GE) notified management in November 2008 that they elected to terminate the Master Leasing Agreements in accordance with the termination rights specified within the contract. In 2011, OPCo will be required to purchase all equipment under the lease and pay GE an amount equal to the unamortized value of all equipment then leased. As a result, the unamortized value of this equipment of $17.2 million is reflected in future minimum lease payments for 2011.

In December 2008 and 2009, management signed new master lease agreements with one-year commitment periods that include lease terms of up to 10 years.

For equipment under the GE master lease agreements that expire in 2011, the lessor is guaranteed receipt of up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, OPCo is committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. Under the new master 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 market 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. At December 31, 2009, the maximum potential loss for these lease agreements assuming the fair market value of the equipment is zero at the end of the lease term was $4.6 million. Historically, at the end of the lease term the fair market value has been in excess of the unamortized balance.

Gavin Lease

OPCo had a lease agreement with JMG to finance OPCo's FGD system installed on OPCo's Gavin Plant. The PUCO approved the original lease agreement between OPCo and JMG. JMG owned and leased the FGD to OPCo. JMG was considered a single-lessee leasing arrangement with only one asset. OPCo's lease payments were the only form of repayment associated with JMG's debt obligations even though OPCo did not guarantee JMG's debt. The creditors of JMG had no recourse to any AEP entity other than OPCo for the lease payment. OPCo accounts for the lease agreement as an operating lease. In April 2009, OPCo paid JMG $58 million which was used to retire certain long-term debt of JMG. While this payment was not contractually required, OPCo made this payment in anticipation of purchasing the outstanding equity of JMG. In July 2009, OPCo purchased all of the outstanding equity ownership of JMG for $28 million which resulted in an increase in equity of $37 million. In August and September 2009, JMG reacquired $218 million of auction rate debt, funded by OPCo capital contributions to JMG. These reacquisitions were not contractually required. In December 2009, the lease was cancelled and all the assets and liabilities of JMG were transferred to OPCo.

11. FINANCING ACTIVITIES

Preferred Stock

Par Value	Authorized Shares	Shares Outstanding at December 31, 2009	Call Price at December 31, 2009 (a)	Series	Redemption	December 31, 2009	December 31, 2008
						(in thousands)	
$ 25	4,000,000	-	$ -	-	-	$ -	$ -
100	(b)	14,595	103.00	4.08%	Any time	1,460	1,460
100	(b)	22,824	103.20	4.20%	Any time	2,282	2,282
100	(b)	31,482	104.00	4.40%	Any time	3,148	3,148
100	(b)	97,363	110.00	4.50%	Any time	9,737	9,737

(a) The cumulative preferred stock is callable at the price indicated plus accrued dividends. If OPCo defaults on preferred stock dividend payments for a period of one year or longer, preferred stock holders are entitled, voting separately as one class, to elect the number of directors necessary to constitute a majority of OPCo's full board of directors.
(b) OPCo has 3,762,403 authorized $100 par value per share shares in total.

OPCo redeemed 5 shares of its 4.50% series cumulative preferred stock in March 2010.

OPCo redeemed 10 shares of its 4.50% series cumulative preferred stock in the year ended December 31, 2009. No shares of preferred stock were redeemed in 2008.

Long-term Debt

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

The following details long-term debt outstanding as of December 31, 2009 and 2008:

Type of Debt	Maturity	Weighted Average Interest Rate at December 31, 2009	Interest Rate Ranges at December 31, 2009	Interest Rate Ranges at December 31, 2008	Outstanding at December 31, 2009	Outstanding at December 31, 2008
					(in thousands)	
Senior Unsecured Notes	2010-2033	4.91%	0.4644%-6.60%	4.3875%-6.60%	$ 2,650,000	$ 2,150,000
Pollution Control Bonds (a)	2010-2037 (b)	3.52%	0.22%-7.125%	0.85%-13.00%	398,580	359,450
Notes Payable – Affiliated	2015	5.25%	5.25%	5.25%	200,000	200,000
Unamortized Discount					(6,075)	(4,704)
Total Long-term Debt					$ 3,242,505	$ 2,704,746

(a) Under the terms of the pollution control bonds, OPCo is required to pay amounts sufficient to enable the payment of interest on and the principal of (at stated maturities and upon mandatory redemptions) related pollution control revenue bonds issued to finance the construction of pollution control facilities at certain plants. For certain series of pollution control bonds, interest rates are subject to periodic adjustment. Interest payments range from monthly to semi-annually. Letters of credit from banks, standby bond purchase agreements and insurance policies support certain series.

(b) Certain pollution control bonds are subject to mandatory 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 at December 31, 2009 is payable as follows:

	(in thousands)
2010	$ 679,450
2011	-
2012	-
2013	500,000
2014	325,000
After 2014	1,744,130
Total Principal Amount	3,248,580
Unamortized Discount	(6,075)
Total	$ 3,242,505

In March 2010, OPCo issued $86 million of 3.125% Pollution Control Bonds due in 2015.

On behalf of OPCo, trustees held $303 million of reacquired auction-rate tax-exempt long-term debt at December 31, 2009.

Dividend Restrictions

OPCo pays dividends to the Parent provided funds are legally available. Various financing arrangements, charter provisions and regulatory requirements may impose certain restrictions on the ability to transfer funds to the 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. As applicable, OPCo understands "capital account" to mean the par value of the common stock multiplied by the number of shares outstanding.

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

Charter and Leverage Restrictions

Provisions within the articles or certificates of incorporation relating to preferred stock or shares restrict the payment of cash dividends on common and preferred stock or shares. Pursuant to credit agreement leverage restrictions, as of December 31, 2009, approximately $84 million of the retained earnings of OPCo have restrictions related to the payment of dividends.

Utility Money Pool – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of its subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the 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, 2009 is included in Notes Receivable from Associated Companies on the balance sheets. The amount of outstanding borrowings from the Utility Money Pool as of December 31, 2008 is included in Notes Payable to Associated Companies on the balance sheets. OPCo's money pool activity and its corresponding authorized borrowing limits for the years ended December 31, 2009 and 2008 are described in the following tables:

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 (Borrowings) to/from Utility Money Pool as of December 31,	Authorized Short-Term Borrowing Limit
	(in thousands)					
2009	$ 522,934	$ 451,832	$ 255,870	$ 302,420	$ 438,352	$ 600,000
2008	415,951	82,486	160,127	28,573	(133,887)	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, 2009 and 2008 were as follows:

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
2009	2.28%	0.43%	0.77%	0.15%	1.21%	0.22%
2008	5.37%	2.28%	5.47%	3.36%	3.24%	3.82%

Interest expense related to the Utility Money Pool is included in Interest Charges. OPCo incurred interest expense for amounts borrowed from the Utility Money Pool of $2 million and $5 million for the years ended December 31, 2009 and 2008, 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 $228 thousand and $79 thousand for the years ended December 31, 2009 and 2008, respectively.

Credit Facilities

OPCo and certain other companies in the AEP System have a $627 million 3-year credit agreement. Under the facility, letters of credit may be issued. As of December 31, 2009, $167 million of letters of credit were issued by OPCo under the 3-year credit agreement to support variable rate Pollution Control Bonds.

OPCo and certain other companies in the AEP System had a $350 million 364-day credit agreement that expired in April 2009.

Sale of Receivables – AEP Credit

AEP Credit has a sale of receivables agreement with bank conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires from affiliated utility subsidiaries to the bank conduits and receives cash.

In July 2009, AEP renewed and increased AEP Credit's sale of receivables agreement. The sale of receivables agreement provides a commitment of $750 million from bank conduits to purchase receivables from AEP Credit. This agreement will expire in July 2010. AEP intends to extend or replace the sale of receivables agreement.

AEP Credit purchases accounts receivable through purchase agreements with OPCo. Under the factoring 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 financing costs, uncollectible accounts experience for OPCo's receivables and administrative costs.

The amount of factored accounts receivable and accrued unbilled revenues was $161 million and $138.1 million at December 31, 2009 and 2008, respectively.

The fees paid to AEP Credit for factoring customer accounts receivable were $8.8 million and $10 million for the years ended December 31, 2009 and 2008, respectively.

12. RELATED PARTY TRANSACTIONS

For other related party transactions, also see "Utility Money Pool – AEP System" and "Sale of Receivables – AEP Credit" sections of Note 11.

AEP Power Pool

OPCo, along with APCo, CSPCo, I&M and KPCo are parties to the Interconnection Agreement, dated July 6, 1951, as amended, defining how they share the costs and benefits associated with their generating plants. This sharing is based upon each company's MLR, which is calculated monthly on the basis of each company's maximum peak demand in relation to the sum of the maximum peak demands of all five companies during the preceding 12 months. In addition, since 1995, OPCo, along with APCo, CSPCo, I&M and KPCo, have been 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.

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

CSW Operating Agreement

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

System Integration Agreement (SIA)

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

Power generated, allocated or provided under the Interconnection Agreement or CSW Operating Agreement is primarily sold to customers at rates 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 native load of the AEP System is sold in the wholesale market by AEPSC on behalf of the generating company.

Affiliated Revenues and Purchases

The following table shows the revenues derived from sales to the pools, direct sales to affiliates, natural gas contracts with AEPES and other revenues for the years ended December 31, 2009 and 2008:

Related Party Revenues	Years Ended December 31, 2009	2008
	(in thousands)	
Sales to AEP Power Pool	$ 935,563	$ 849,574
Direct Sales to East Affiliates	84,078	74,465
Direct Sales to West Affiliates	1,384	11,505
Natural Gas Contracts with AEPES	(6,142)	(689)
Other	19,407	5,613

The following table shows the purchased power expense incurred from purchases from the pools and affiliates for the years ended December 31, 2009 and 2008:

Related Party Purchases	Years Ended December 31, 2009	2008
	(in thousands)	
Purchases from AEP Power Pool	$ 72,360	$ 135,514
Direct Purchases from West Affiliates	987	1,483
Gas Purchases from AEPES	1,251	3,689

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 and
- 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.

OPCo, along with APCo, CSPCo, I&M and KPCo are parties to the TA, dated April 1, 1984, as amended, 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). Like the Interconnection Agreement, this sharing is based upon each company's MLR.

OPCo's net charges allocated under the TA during the years ended December 31, 2009 and 2008 were $8.5 million and $13.3 million, respectively. The net charges are recorded in Operation Expenses.

PSO, SWEPCo, TNC and AEPSC are parties to the TCA, originally dated January 1, 1997, as amended. 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, including 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 Open Access Transmission Tariff (OATT) filed with the FERC and the rules of the FERC relating to such tariff.

Natural Gas Contracts with DETM

In 2003, AEPES assigned to AEPSC, as agent for the AEP East companies, approximately $97 million (negative value) associated with its natural gas contracts with DETM. The assignment was executed in order to consolidate DETM positions within AEP. Concurrently, in order to ensure that there would be no financial impact to the AEP East companies, PSO or SWEPCo as a result of the assignment, AEPES and AEPSC entered into agreements requiring AEPES to reimburse AEPSC for any related cash settlements and all income related to the assigned contracts. OPCo's risk management liabilities related to DETM at December 31, 2009 and 2008 were $1.6 million and $3.6 million, respectively.

Fuel Agreement between OPCo and AEPES

OPCo and National Power Cooperative, Inc. (NPC) have an agreement whereby OPCo operates a 500 MW gas plant owned by NPC (Mone Plant). AEPES entered into a fuel management agreement with OPCo and NPC to manage and procure fuel for the Mone Plant. The gas purchased by AEPES and used in generation is first sold to OPCo then allocated to the AEP East companies, who have an agreement to purchase 100% of the available generating capacity from the plant through May 2012. OPCo's purchases of gas managed by AEPES were $279 thousand and $840 thousand for the years ended December 31, 2009 and 2008, respectively. These purchases are reflected in Operation Expenses.

Jointly-Owned Electric Facilities

APCo and OPCo jointly own the Amos Plant and the Sporn Plant. The costs of operating these facilities are apportioned between owners based on ownership interests. OPCo's share of these costs is included in the appropriate expense accounts on its Statement of Income. OPCo's investment in these plants is included in Utility Plant on its Comparative Balance Sheet.

Cook Coal Terminal

In 2009 and 2008, Cook Coal Terminal, a division of OPCo, performed coal transloading services at cost for APCo and I&M. OPCo included revenues for these services of $19.8 million and $16.4 million for the years ended December 31, 2009 and 2008, respectively, in Revenues from Nonutility Operations and expenses in Expenses of Nonutility Operations on its Statement of Income.

In addition, Cook Coal Terminal provided coal transloading services for OVEC in 2008. Cook Coal Terminal did not provide coal transloading services for OVEC in 2009. OPCo recorded revenue in the amount of $59 thousand in 2008. OVEC is 43.47% owned by AEP (includes CSPCo's 4.3% ownership of OVEC).

In 2009 and 2008, Cook Coal Terminal also performed railcar maintenance services at cost for APCo, I&M, PSO and SWEPCo. OPCo includes revenues for these services in Revenues from Nonutility Operations and expenses in Expenses of Nonutility Operations on its Statement of Income. The railcar maintenance revenues were $3.6 million and $4.4 million for the years ended December 2009 and 2008, respectively.

In addition, Cook Coal Terminal provided railcar maintenance services for OVEC in 2009 and 2008. OPCo recorded revenue as Revenues from Nonutility Operations on its Statement of Income in the amount of $1 million, for each year in 2009 and 2008. OVEC is 43.47% owned by AEP (includes CSPCo's 4.3% ownership of OVEC).

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 records these costs of $38 million and $41 million for the years ended December 31, 2009 and 2008, respectively, as Operation Expenses.

Central Machine Shop

APCo operates a facility which repairs and rebuilds specialized components for the generation plants across the AEP System. APCo defers on its Comparative Balance Sheet the cost of performing the services, then transfers the cost to the affiliate for reimbursement. OPCo recorded these billings as capital or maintenance expense depending on the nature of the services received. These billings are recoverable from customers. OPCo was billed $2.8 million and $1.9 million by APCo for the years ended December 31, 2009 and 2008, respectively.

Affiliate Coal Purchases

In 2008, OPCo entered into contracts to sell excess coal to certain AEP subsidiaries through 2010. The realized and unrealized amounts recorded on its Statement of Income for the years ended December 31, 2009 and 2008 were $5.0 million and $534 thousand, respectively.

Affiliate Railcar Agreement

OPCo has an agreement providing for the use of affiliates' 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 records these costs or reimbursements as costs or reduction of costs, respectively, in Fuel Stock on its Comparative Balance Sheet and such costs are recoverable from customers. Under the agreement, OPCo billed its affiliates $4.3 million and $4.2 million and paid its affiliates $1.9 million and $1.6 million for the years ended December 31, 2009 and 2008, respectively.

Purchased Power from OVEC

The amounts of power purchased by OPCo from OVEC, which is 43.47% owned by AEP (includes CSPCo's 4.3% ownership of OVEC), for the years ended December 31, 2009 and 2008 were $102.1 million and $93.7 million, respectively. The amounts shown above are recoverable from customers and are included in Operation Expenses on the Statement of Income.

AEP Power Pool Purchases from OVEC

The AEP Power Pool purchased power from OVEC as part of wholesale marketing and risk management activity. The agreement ended in December 2008. OPCo's amount recorded for the year ended December 31, 2008 was $12.4 million.

Sales and Purchases of Property

OPCo had affiliated sales and purchases of electric property individually amounting to $100 thousand or more for the years ended December 31, 2009 and 2008 as shown in the following table:

	Years Ended December 31,	
	2009	2008
Companies	(in thousands)	
APCo to OPCo	$ -	$ 615
I&M to OPCo	6,378	1,992
OPCo to APCo	908	-
OPCo to CSPCo	344	-
OPCo to I&M	6,026	1,800
OPCo to PSO	-	259
OPCo to TCC	526	-

In addition, OPCo had aggregate affiliated sales and purchases of meters and transformers for the years ended December 31, 2009 and 2008 as shown in the following tables:

	APCo	CSPCo	I&M	KPCo	PSO	SWEPCo	TCC	TNC	WPCo	Total
Sales					(in thousands)					
2009	$ 372	$ 2,748	$ 297	$ 87	$ 6	$ 85	$ 1	$ 44	$ 464	$ 4,104
2008	249	3,446	613	95	2	16	14	11	562	5,008
Purchases										
2009	$ 115	$ 664	$ 315	$ 133	$ 1	$ 58	$ 19	$ 17	$ 170	$ 1,492
2008	206	580	270	121	4	3	1	9	152	1,346

The amounts above are recorded in Utility Plant at cost.

Global Borrowing Notes

AEP issued long-term debt, portions of which were loaned to OPCo. AEP pays the interest on the global notes, but OPCo accrues interest for its borrowing and remits the interest to AEP. The accrued interest is reflected in Interest Accrued on the Comparative Balance Sheet.

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 bases 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. Billings are capitalized or expensed depending on the nature of the services rendered.

AEPSC

AEPSC provides certain managerial and professional services to AEP's subsidiaries. AEP is the sole equity owner of AEPSC. 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. No AEP subsidiary has provided financial or other support outside of the reimbursement of costs for services rendered. AEPSC finances its operations by cost reimbursement from other AEP subsidiaries. There are no other terms or arrangements between AEPSC and any of the AEP subsidiaries that could require additional financial support from an AEP subsidiary or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. AEP's subsidiaries are exposed to losses to the extent they cannot recover the costs of AEPSC through their normal business operations. In the event AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP. OPCo's total billings from AEPSC were $175 million and $208 million for the years ended December 31, 2009 and 2008, respectively.

13. 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	Hydro	Transmission	Distribution	General
			(in percentages)		
2009	3.4	2.7	2.3	3.9	11.5
2008	2.7	2.6	2.3	3.9	8.5

For cost-based 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 2009 and 2008 aggregate carrying amounts of ARO related to ash disposal facilities and asbestos removal:

Year	ARO at January 1,	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates	ARO at December 31,
			(in thousands)			
2009	$ 89,316	$ 7,935	$ -	$ (3,946)	$ 916	$ 94,221
2008	77,354	5,786	212	(4,148)	10,112	89,316

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 2009/Q4

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

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

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year			(253,927)	(37,697,485)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income			14,699	2,813,016
3	Preceding Quarter/Year to Date Changes in Fair Value			64,756	(102,623,841)
4	Total (lines 2 and 3)			79,455	(99,810,825)
5	Balance of Account 219 at End of Preceding Quarter/Year			(174,472)	(137,508,310)
6	Balance of Account 219 at Beginning of Current Year			(174,472)	(137,508,310)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income			4,473	6,353,956
8	Current Quarter/Year to Date Changes in Fair Value				890,572
9	Total (lines 7 and 8)			4,473	7,244,528
10	Balance of Account 219 at End of Current Quarter/Year			(169,999)	(130,263,782)

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 2009/Q4

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges Commodity (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	2,166,999	(756,770)	(36,541,183)		
2	662,906	851,118	4,341,739		
3	(902,743)	1,802,697	(101,659,131)		
4	(239,837)	2,653,815	(97,317,392)	231,122,882	133,805,490
5	1,927,162	1,897,045	(133,858,575)		
6	1,927,162	1,897,045	(133,858,575)		
7	(500,225)	(1,742,446)	4,115,758		
8	10,914,883	(520,756)	11,284,699		
9	10,414,658	(2,263,202)	15,400,457	306,572,997	321,973,454
10	12,341,820	(366,157)	(118,458,118)		

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 2009/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)	8,820,955,036	8,820,955,036
4	Property Under Capital Leases	20,296,060	20,296,060
5	Plant Purchased or Sold		
6	Completed Construction not Classified	836,406,578	836,406,578
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	9,677,657,674	9,677,657,674
9	Leased to Others		
10	Held for Future Use	2,953,379	2,953,379
11	Construction Work in Progress	198,843,300	198,843,300
12	Acquisition Adjustments	636,578	636,578
13	Total Utility Plant (8 thru 12)	9,880,090,931	9,880,090,931
14	Accum Prov for Depr, Amort, & Depl	3,403,633,125	3,403,633,125
15	Net Utility Plant (13 less 14)	6,476,457,806	6,476,457,806
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	3,336,057,182	3,336,057,182
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	67,051,494	67,051,494
22	Total In Service (18 thru 21)	3,403,108,676	3,403,108,676
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	Total Held for Future Use (28 & 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj	524,449	524,449
33	Total Accum Prov (equals 14) (22,26,30,31,32)	3,403,633,125	3,403,633,125

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 2009/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
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					33

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 2009/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

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

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)
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)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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
			3
			4
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			22

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 2009/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	5,009	
3	(302) Franchises and Consents	66,769	
4	(303) Miscellaneous Intangible Plant	98,458,699	6,555,451
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	98,530,477	6,555,451
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	7,800,962	6,768
9	(311) Structures and Improvements	355,478,134	23,263,090
10	(312) Boiler Plant Equipment	3,957,102,856	1,405,002,491
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	597,665,251	42,799,183
13	(315) Accessory Electric Equipment	186,874,495	3,554,049
14	(316) Misc. Power Plant Equipment	64,886,819	7,401,505
15	(317) Asset Retirement Costs for Steam Production	32,757,670	935,129
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	5,202,566,187	1,482,962,215
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	49,964,061	
29	(332) Reservoirs, Dams, and Waterways	6,304,465	
30	(333) Water Wheels, Turbines, and Generators	42,410,730	11,071
31	(334) Accessory Electric Equipment	10,009,149	
32	(335) Misc. Power PLant Equipment	4,343,692	12,775
33	(336) Roads, Railroads, and Bridges		
34	(337) Asset Retirement Costs for Hydraulic Production	4,136	
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	113,040,225	23,846
36	D. Other Production Plant		
37	(340) Land and Land Rights		
38	(341) Structures and Improvements		
39	(342) Fuel Holders, Products, and Accessories		
40	(343) Prime Movers		
41	(344) Generators		
42	(345) Accessory Electric Equipment		
43	(346) Misc. Power Plant Equipment		
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)		
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	5,315,606,412	1,482,986,061

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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	60,591,617	1,519,940
49	(352) Structures and Improvements	30,797,685	5,305
50	(353) Station Equipment	588,185,422	35,638,640
51	(354) Towers and Fixtures	139,201,718	8,829
52	(355) Poles and Fixtures	109,553,718	10,899,319
53	(356) Overhead Conductors and Devices	179,902,447	7,949,264
54	(357) Underground Conduit	366,433	
55	(358) Underground Conductors and Devices	829,227	75,564
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)	1,109,431,387	56,096,861
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	14,872,004	6,640,462
61	(361) Structures and Improvements	7,463,400	85,744
62	(362) Station Equipment	196,044,417	42,259,517
63	(363) Storage Battery Equipment	5,727,740	229,426
64	(364) Poles, Towers, and Fixtures	303,295,184	17,284,893
65	(365) Overhead Conductors and Devices	261,717,402	24,476,040
66	(366) Underground Conduit	49,272,639	1,766,084
67	(367) Underground Conductors and Devices	85,970,981	4,781,933
68	(368) Line Transformers	308,135,970	12,939,618
69	(369) Services	128,170,959	6,522,833
70	(370) Meters	69,993,692	4,482,364
71	(371) Installations on Customer Premises	21,303,602	1,699,268
72	(372) Leased Property on Customer Premises	1,104	
73	(373) Street Lighting and Signal Systems	20,496,896	1,212,204
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,472,465,990	124,380,386
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	5,439,338	-312,637
87	(390) Structures and Improvements	70,724,850	2,041,463
88	(391) Office Furniture and Equipment	3,098,660	129,203
89	(392) Transportation Equipment	13,125,509	2,675
90	(393) Stores Equipment	271,254	-1,557
91	(394) Tools, Shop and Garage Equipment	13,555,573	1,739,857
92	(395) Laboratory Equipment	570,347	
93	(396) Power Operated Equipment	630,645	
94	(397) Communication Equipment	31,942,478	1,328,776
95	(398) Miscellaneous Equipment	1,695,990	732,963
96	SUBTOTAL (Enter Total of lines 86 thru 95)	141,054,644	5,660,743
97	(399) Other Tangible Property	14,286,236	
98	(399.1) Asset Retirement Costs for General Plant	165,163	
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	155,506,043	5,660,743
100	TOTAL (Accounts 101 and 106)	8,151,540,309	1,675,679,502
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)	8,151,540,309	1,675,679,502

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
			5,009		2
			66,769		3
28,774,962			76,239,188		4
28,774,962			76,310,966		5
					6
					7
		-1,095,298	6,712,432		8
2,642,186		1,515,948	377,614,986		9
67,188,193		-1,601,194	5,293,315,960		10
					11
19,346,480		1,292,030	622,409,984		12
885,375		24,800	189,567,969		13
200,506		-6,941	72,080,877		14
			33,692,799		15
90,262,740		129,345	6,595,395,007		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
			3,992		27
			49,964,061		28
			6,304,465		29
3,523			42,418,278		30
			10,009,149		31
4,595			4,351,872		32
					33
			4,136		34
8,118			113,055,953		35
					36
					37
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					45
90,270,858		129,345	6,708,450,960		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 2009/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
			62,111,557		48
2,372		4,921,135	35,721,753		49
4,618,488		-259,578	618,945,996		50
14,630			139,195,917		51
864,562			119,588,475		52
334,664			187,517,047		53
			366,433		54
3,405			901,386		55
					56
			3,120		57
5,838,121		4,661,557	1,164,351,684		58
					59
2,532			21,509,934		60
		521,722	8,070,866		61
1,696,677		636,064	237,243,321		62
		-894,967	5,062,199		63
3,143,127			317,436,950		64
7,872,336			278,321,106		65
10,938			51,027,785		66
686,643			90,066,271		67
8,144,112			312,931,476		68
1,982,135			132,711,657		69
4,608,690		-28,041	69,839,325		70
1,005,452			21,997,418		71
			1,104		72
782,669			20,926,431		73
					74
29,935,311		234,778	1,567,145,843		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
158,294			4,968,407		86
1,384,015		-4,921,135	66,461,163		87
			3,227,863		88
13,096,441			31,743		89
			269,697		90
227,759		324,871	15,392,542		91
			570,347		92
			630,645		93
209,026			33,062,228		94
44,368		-324,872	2,059,713		95
15,119,903		-4,921,136	126,674,348		96
12,700			14,273,536		97
10,886			154,277		98
15,143,489		-4,921,136	141,102,161		99
169,962,741		104,544	9,657,361,614		100
					101
					102
					103
169,962,741		104,544	9,657,361,614		104

FOOTNOTE DATA

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

Nature and Use of Plant Included in Account 399:

Muskingum Mine Conveyor System	$13,413,744
Other Coal Property Interest and Equipment	859,792
	$14,273,536

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 2009/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					
2					
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42					
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44					
45					
46					
47	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 2009/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	Cornerstone Substation (4402)	10/1/09	2010	285,404
8				
9				
10	Items Under $250,000			1,986,020
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22				
23				
24				
25				
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44				
45				
46				
47	Total			2,953,379

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 2009/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	STATE OF OHIO	
2	OP/Sectionalizing Program	157,963
3	Muskingum River Upper Reservoir Exp	2,561,546
4	MR U5 FGD Landfill	2,561,772
5	AM Plant Landfill	306,428
6	OP R/W Widening	173,352
7	EIMS: GHG & TITLE V MODEL	1,097,790
8	TS OP Wooster Trans Station Im	6,678,215
9	OPCo- pilot wire rehabilitaions	783,227
10	OPCo- pilot wire rehabilitaions	428,200
11	OP/Trans CKT Reliab Program	2,470,658
12	OPCo- Line Rehab Program	1,375,518
13	Circuit Breaker Rehab Program-OPCO	1,150,108
14	Circuit Breaker Rehab Program-OPCO	111,248
15	OPCo- Relay Rehab Projects	3,800,362
16	OPCo- Relay Rehab Projects	502,483
17	OPCO- RTU replacement prog	177,194
18	OPCO- RTU replacement prog	107,538
19	CCTV-IDS FOR OP-D	115,271
20	ACCESS CONTROL OPCO-G	569,770
21	TS/OP/Phase I Don Marquis	1,569,724
22	CCTV-IDS FOR GL 160	206,790
23	ACCESS CONTROL OPCO-T	171,492
24	OPCo Hg Monitoring Project- MR	6,324,920
25	TS/OPC/Cambridge Area Improve	1,847,959
26	DS/OPC/Cambridge area improve	385,410
27	TS/OPC/Purchase-Rebuild Maj Eq	5,337,990
28	DS/OPC/Purchase-Rebuild Eq	2,190,348
29	T/OPC/Metering Upgrade	526,989
30	D/OPCO/D Brkr Task Force	459,811
31	TL/OP/Wooster Trans Line Impr	853,673
32	TS/OP/Moreland Trans Station	111,398
33	TL/OP/Moreland Trans Line Imp	916,043
34	DS/OP/Moreland Dist Stat Impro	182,065
35	TL/OPCO/Fremont	138,057
36	T/OPCO/EHV Metering/CB Upgrade	5,692,105
37	ML FGD WWT Hg	323,757
38	OP/Cutout-Arrester	382,092
39	OPCO Towboat Acctg Change	2,310,036
40	TS/OPC/Replace and Refurbish	8,289,247
41	DS/OPCO/Replace&Refurbish	847,258
42	South Point Service Center	1,068,213
43	TOTAL	198,843,300

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 2009/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	OP/Xfmer Monitor Equipment	172,449
2	MT VERNON RE-ROOF PROJ	117,657
3	TL/OPCo/Sporn-Muskingum 345kV	1,453,986
4	CD12 SILO 6 STRUCTURAL -OHIO	504,228
5	AM U3 Ash Disposal Project OP	18,857,624
6	CD0 land fill add cell 3	2,173,125
7	CD1&2 SCR YR OPER OP PRJ	1,269,678
8	CD1 ADSP SPARE RTR AND NOZZLE	3,471,879
9	OP/Stanley Court Station	1,797,665
10	OP/Sunnyside-Stanley Ct 23kV	223,599
11	OP/Canton Ntwk Duct,Vault,MH	3,820,594
12	OP/Canton Ntwk Fdrs,Cables	4,080,966
13	OP Strasburg Distr Auto Line	175,273
14	OP/Shreve Repl w/9.38MVA	1,854,132
15	OP/Shreve Sta 69kV Exit Spans	216,841
16	OP/California Sta 4 12kV Ckts	155,365
17	OP California Station	152,718
18	OP Madisonburg Station	243,885
19	OP/Madisonburg Sta 69kV Line	341,797
20	OP/Madisonburg Sta ROW	682,702
21	OP N Fremont Station	1,588,535
22	OP Frederick Station	1,639,933
23	Ds-Op-Ai Pole Replacement	242,438
24	Ds-Op-Ai Recloser Replacement	287,309
25	Replace HP Turbine Assembly	347,747
26	Purchase Install GSU Phase 1	2,042,875
27	Add 4th Layer SCR Catalyst	4,178,188
28	BFPT Last Stage Blade Replacem	230,860
29	NRX ASSET HUB - OHIO PWR	105,929
30	NRX ASSET HUB - CARDINAL-OPCo	131,487
31	Indus Upgrade for OPCO Trans	363,549
32	Indus Upgrade for OPCO Gen	2,025,651
33	Indus Upgrade for OPCO Distr	694,307
34	gridSMART-OPCO-D	2,048,855
35	KM U 123 Fuel Switch (NSR)	19,418,355
36	ML0 SCR YR AROUND OPER CAP REQ	2,797,808
37	ML1-SCR ADD CATALYST LAYER	3,132,530
38	ML-REPLACE MANLIFTS U2	1,260,151
39	MRU5 Cooling Tower Drift Elims	308,784
40	MRU5 2nd RH Bank Replc	6,012,529
41	RCH CAPITAL ASSOC TO OVERHAUL	1,094,324
42	SP U2 & U4 Carbon Inject OPCO	232,614
43	TOTAL	198,843,300

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 2009/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	Conners Run Impoundment Expansion	12,207,847
2	WS-CI-OPCo-G PPB	12,768,465
3	ET-CI-OPCo-T CUST SERV	655,160
4	ET-CI-OPCo-T PPR	164,113
5	ET-CI-OPCo-T SYS IMP	4,828,503
6	ED-CI-OPCo-D AST IMP	3,075,446
7	ED-CI-OPCo-D CUST MTR	750,116
8	ED-CI-OPCo-D CUST SERV	1,739,923
9	ED-CI-OPCo-D LN TRNSF	360,413
10	ED-CI-OPCo-D PPR	162,549
11	EC-CI-OPCo-D TELECOM	209,447
12	SS-CI-OPCo-T GEN PLT	389,818
13	SS-CI-OPCo-D GEN PLT	120,925
14	WS-OPCo-G	625,392
15	ET-OPCo-T	403,620
16	ED-OPCo-D	1,140,898
17	SS-CI-OPCo-T Software	113,275
18	SS-CI-OPCo-G Software	549,851
19	SS-CI-OPCo-D Software	394,622
20	ET-CI-OPCo-T Drvn D Asset Imp	931,887
21	OPCo-D Service Restoration Blk	413,815
22	OPCo-D Third Party Work Blkt	-1,492,173
23	Other Minor Projects Under $100,000	1,114,447
24	TOTAL STATE OF OHIO: $198,843,300	
25		
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42		
43	TOTAL	198,843,300

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 2009/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	2,858,669,467	2,858,669,467		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	306,616,519	306,616,519		
4	(403.1) Depreciation Expense for Asset Retirement Costs	3,514,476	3,514,476		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing				
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):	40,099	40,099		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	310,171,094	310,171,094		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	140,785,741	140,785,741		
13	Cost of Removal	35,159,039	35,159,039		
14	Salvage (Credit)	62,320,672	62,320,672		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	113,624,108	113,624,108		
16	Other Debit or Cr. Items (Describe, details in footnote):	280,840,729	280,840,729		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	3,336,057,182	3,336,057,182		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	2,212,010,282	2,212,010,282		
21	Nuclear Production				
22	Hydraulic Production-Conventional	70,282,219	70,282,219		
23	Hydraulic Production-Pumped Storage				
24	Other Production				
25	Transmission	497,042,871	497,042,871		
26	Distribution	503,030,507	503,030,507		
27	Regional Transmission and Market Operation				
28	General	53,691,303	53,691,303		
29	TOTAL (Enter Total of lines 20 thru 28)	3,336,057,182	3,336,057,182		

FOOTNOTE DATA

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

Depreciation on incremental Monongahela costs	$ 35,547
Asbestos depreciation & accretion reclassed to account 1080013	4,552
TOTAL	$ 40,099

Schedule Page: 219 Line No.: 12 Column: c

Difference in retirements reported on page 204 and 219 is the undepreciated balance of retired Cheaspeake and Ironton Service Center Asbestos ARO's.

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

RWIP transferred to In-Service	-$ 10,728,586
ARO Removal in account 1080013	- 22,165
JMG acquisition	283,690,621
Transfer reserve for JMG Leasehold Improvements	6,621,591
Transfer between reserve accounts	1,279,268
	$280,840,729

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 2009/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			129,684
3	250 Shares Common Stock	01/01/68		250
4				
5	Subtotal			129,934
6	CENTRAL COAL COMPANY:			
7	1,500 Shares Common Stock	01/01/48		603,868
8				
9	Subtotal			603,868
10				
11	JMG FUNDING, LLC	07/22/09		
12				
13	Subtotal			
14	NOTE: During 2009, Ohio Power Company acquired 100% equity			
15	ownership of JMG Funding LLC from third parties.			
16	On December 15, 2009, JMG Funding LLC, transferred all assets and			
17	liabilities to Ohio Power Company.			
18				
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41				
42	Total Cost of Account 123.1 $ 733,802		TOTAL	733,802

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 2009/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues form investments, including such revenues form securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
		129,684		2
		250		3
				4
		129,934		5
				6
		603,868		7
				8
		603,868		9
				10
7,130,187				11
				12
7,130,187				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
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7,130,187		733,802		42

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 2009/Q4

MATERIALS AND SUPPLIES

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

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	181,786,183	327,108,624	Electric
2	Fuel Stock Expenses Undistributed (Account 152)	5,117,530	9,757,875	Electric
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	62,444,751	51,694,377	Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	27,344,362	47,638,635	Electric
8	Transmission Plant (Estimated)	917,697	1,536,995	Electric
9	Distribution Plant (Estimated)	4,761,099	4,889,208	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	689,216	473,871	Electric
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	96,157,125	106,233,086	
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)	283,060,838	443,099,585	

FOOTNOTE DATA

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

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

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 2009/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.	Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2010 No. (d)	2010 Amt. (e)
1	Balance-Beginning of Year	342,831.00	10,603,780	250,368.00	2,472,386
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	AEP System Pool	66,866.00	6,549,666		
10	Buckeye Power Company	3,959.00	281,089		
11					
12					
13					
14					
15	Total	70,825.00	6,830,755		
16					
17	Relinquished During Year:				
18	Charges to Account 509	160,336.00	5,292,446		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22	Appalachian Power Co.	75,566.00	3,621,904		
23	Columbus Southern Power	32,707.00	1,567,657		
24	Kentucky Power Co.	10,582.00	507,199		
25					
26					
27					
28	Total	118,855.00	5,696,760		
29	Balance-End of Year	134,465.00	6,445,329	250,368.00	2,472,386
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)		718,554		
34	Gains		13,825,565		
35	Losses		4,129,102		
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year	3,256.00		3,247.00	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	3,256.00			
40	Balance-End of Year			3,247.00	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)		227,872		
45	Gains		227,872		
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 2009/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.

2011		2012		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
261,010.00	3,877,536	243,184.00	4,081,896	6,031,484.00	10,394,524	7,128,877.00	31,430,122	1
								2
								3
				230,864.00		230,864.00		4
								5
								6
								7
								8
						66,866.00	6,549,666	9
						3,959.00	281,089	10
								11
								12
								13
								14
						70,825.00	6,830,755	15
								16
								17
						160,336.00	5,292,446	18
								19
								20
								21
						75,566.00	3,621,904	22
						32,707.00	1,567,657	23
						10,582.00	507,199	24
								25
								26
								27
						118,855.00	5,696,760	28
261,010.00	3,877,536	243,184.00	4,081,896	6,262,348.00	10,394,524	7,151,375.00	27,271,671	29
								30
								31
								32
							718,554	33
							13,825,565	34
							4,129,102	35
3,247.00		3,256.00		140,143.00		153,149.00		36
				6,511.00		6,511.00		37
								38
				3,256.00		6,512.00		39
3,247.00		3,256.00		143,398.00		153,148.00		40
								41
								42
								43
					21,703		249,575	44
					21,703		249,575	45
								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 2009/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		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1						
2						
3						
4						
5						
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7						
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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 2009/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		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
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40						
41						
42						
43						
44						
45						
46						
47						
48						
49	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 2009/Q4

Transmission Service and Generation Interconnection Study Costs

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

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	Buckeye-Pine Ridge 69KV	1	186		
3	Buckeye-Pleasant Township 138KV			1,634	186
4	Buckeye-Ohio Valley Coal 69KV	3,097	186		
5	Buckeye Power-Galatea 34.5KV	1,708	186	5,000	186
6	Buckeye Power-Meeker 34.5KV	816	186	2,000	186
7	Buckeye Power-Berwick/Upp Sandusky			8,085	186
8	Buckeye Power-Uncapher 69KV	2,518	186	5,000	186
9	Buckeye Power-Van Wert 138KV	1,322	186		
10	Buckeye Power-Liberty Hi 34.5KV	2,379	186	5,000	186
11	Buckeye Power-Barn Rd 69KV	3,844	186	5,000	186
12	Buckeye Power-Caldwell 69KV	3,900	186		
13	Buckeye Power-Yeager 69KV	2,120	186		
14	Buckeye Power-Stone Plant 69KV	4,452	186		
15	Buckeye-Straitsville 69KV	2,061	186		
16	City of Dover-69KV	3,124	186		
17	City of Wapakoneta 69KV	1	186		
18	GMEC-Mount Hermon 138KV	1,059	186		
19	Kammer 765/500 KV Transf Repl	29,476	186		
20	N42-AEPSC Moutaineer-Belmont 765KV	733	186		
21	**Generation Studies**				
22	Gavin 1-PJM Facility Study	372	500		
23					
24					
25					
26					
27					
28					
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38					
39					
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 2009/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	P55-Lima Energy-Lima Ohio-Impact	485	186	792	186
3	PJM-#S101 Ohio Central 138KV	6,714	186	9,029	186
4	PJM-#S123 Tiltonsville 138KV	47	186	47	186
5	PJM-#S123 Tiltonsville 138KV	731	186	731	186
6	PJM-#S123/T175 Tiltonsville 69KV	5,592	186		
7	PJM-#S35 Beverly 345KV Duke Energy	162	186	164	186
8	PJM-#T139 (FE-PJM) TSR Facilities	10,000	186	10,000	186
9	PJM-#T139 (FE-PJM) TSR Impact	(1)	186		
10	PJM-#T140 (FE-PJM) TSR Impact	(1)	186		
11	PJM-#T152 North Havervill 69KV	22,370	186	22,370	186
12	PJM-#T175 Tiltonsville 69KV	189	186	1,510	186
13	PJM-#U1-059 Dunkirk 69KV Facility	1,012	186	5,000	186
14	PJM-#U1-059 Dunkirk 69KV Impact	2,162	186	2,163	186
15	PJM-#U1-060 E Lima-S Kenton 138KV	8,229	186	8,229	186
16	PJM-#U2-041 ELima-SMarysville Feas	127	186		
17	PJM-#U2-041 ELima-SMarysville Imp	16,253	186	10,858	186
18	PJM-#U2-042 ELima-SKenton 138KV	134	186	264	186
19	PJM-#U2-042 ELima-SKenton 138KV	2,971	186	274	186
20	PJM-#U2-066 Marysville-SWLima 345	785	186	1,829	186
21	**Generation Studies**				
22					
23					
24					
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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 2009/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-#U4-001 Howard-Fostoria 138KV	842	186	924	186
3	PJM-#U4-001 Howard-Fostoria 138KV	274	186	193	186
4	PJM-#U4-008 S Central Power Feas	22,106	186	21,894	186
5	PJM-#U4-028 W End Fostoria-Chadwik	6,861	186	6,861	186
6	PJM-#U4-028 W End Fostoria-Chadwik	2,981	186	1,849	186
7	PJM-#U4-029 W End Fostoria-Chadwik	648	186	648	186
8	PJM-#U4-029 W End Fostoria-Chadwik	1,052	186	1,051	186
9	PJM-#V1-010 Howard-Fostoria Centrl	9,714	186	8,696	186
10	PJM-#V1-015 NFindlay-NBaltimore	2,593	186	417	186
11	PJM-#V2-001 Howard-Bucyrus Center	3,562	186	2,662	186
12	PJM-#V2-006 ELeipsic 138KV Feas	9,529	186	6,022	186
13	PJM-#V2-020 Howard-W End Fostoria	1,640	186	718	186
14	PJM-#V2-022 Galion-Leesburg 138KV	67	186	67	186
15	PJM-#V2-023 Galion-Muskingum 345KV	244	186	244	186
16	PJM-#V3-028 ELima-Marysville 345KV	28	186	28	186
17	PJM-#V3-029 Chatfield 138KV	1,501	186	28	186
18	PJM-#V4-010 Fremont-Tiffin Centers	64	186		
19	PJM-IPP U2-026 Antwerp 69KV			15	186
20					
21	**Generation Studies**				
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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 2009/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	Balance at Beginning of Current Quarter/Year	Debits	CREDITS		Balance at end of Current Quarter/Year
				Written off During the Quarter/Year Account Charged	Written off During the Period Amount	
	(a)	(b)	(c)	(d)	(e)	(f)
1	SFAS 109 Deferred FIT	162,179,717	62,518,372	Various	67,805,830	156,892,259
2						
3	SFAS 109 Deferred SIT	12,696,052	3,082,441	283.3	218,782	15,559,711
4						
5	SFAS 112 Post Employment Benefits	4,452,638	1,609,184			6,061,822
6						
7	DSM Program Costs		4,006,910			4,006,910
8	- Ohio ESP - Case No. 08-918-EL-SS0					
9						
10	Deferred Storm Expense	10,100,000		593	305,816	9,794,184
11	- Hurricane Ike - Ohio Wind Storm 9/14/08					
12	- Case No. 08-1301-EL-AAM					
13						
14	Deregulation Consumer Education	1,182,995				1,182,995
15						
16	Deregulation Transition Filing	928				928
17						
18	Deregulation Implementation	22,921,712				22,921,712
19						
20	Carrying Charges-Deferred Ohio Deregulation	13,666,621	3,346,028			17,012,649
21						
22	Extension of Local Facilities	24,011,971	11,346,785	421, 456	893,907	34,464,849
23						
24	Reg Asset - Rate Case Expenses	184,302				184,302
25						
26	Deferred Equity Carrying Chgs	(11,319,717)	2,977,983	421	14,020,680	-22,362,414
27	- Amortization periods - 1/2005 up to 12/2019					
28						
29	BridgeCo TO Funding	1,733,561		407.3	96,140	1,637,421
30	- Per FERC Docket No AC04-101-000					
31	- Amortization period - 1/2005 to 12/2019					
32						
33	PJM Integration Payments	3,394,642		407.3	461,989	2,932,653
34	- Per FERC Docket No EL05-74-000					
35	- Amortization period - 1/2005 to 12/2014					
36						
37	Other PJM Integration	1,529,172		407.3	84,804	1,444,368
38	- Per FERC Docket No AC04-101-000					
39	- Amortization period - 1/2005 to 12/2019					
40						
41	Carry Chgs-RTO Start-up Costs	1,434,230	725,656	407.3	846,661	1,313,225
42	- Per FERC Docket No AC04-101-000 and EL05-74-000					
43	- Amortization periods - 1/2005 up to 12/2019					
44	TOTAL	445,237,298	1,003,714,055		710,314,246	738,637,107

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 2009/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	Balance at Beginning of Current Quarter/Year	Debits	CREDITS		Balance at end of Current Quarter/Year
				Written off During the Quarter/Year Account Charged	Written off During the Period Amount	
	(a)	(b)	(c)	(d)	(e)	(f)
1	Alliance RTO Deferred Expense	1,152,234		407.3	63,899	1,088,335
2	- Per FERC Docket No AC04-101-000					
3	- Amortization period - 1/2005 to 12/2019					
4						
5	Def Equity Carrying Charge OH RSP Filing Cst	(54,215)		421	24,868	-79,083
6						
7	Carrying Charge Def OH RSP Filing Cost	90,004	35,269			125,273
8						
9	Ohio Line Extension - Equity Charges	(12,671,117)	471,715	421, 456	5,987,699	-18,187,101
10						
11	Unrecovered Fuel Cost		691,211,591	501	393,641,273	297,570,318
12	- Ohio ESP - Case No. 08-918-EL-SSO					
13						
14	Under-Recovered Ohio TCR Rider	4,838,624	7,355,503	254, 566	12,194,127	
15	-Docket No 05-1194-EL-UNC					
16						
17	Carry Chg-Under Recover Ohio TCR	197,330	295,532	Various	492,862	
18	-Docket No 05-1194-EL-UNC					
19						
20	Carry Chg-Equity Ohio TCR	(92,508)	93,504	421	24,820	-23,824
21	-Docket No 05-1194-EL-UNC					
22						
23	SFAS 158 Employers' Accounting for Defined					
24	Benefit Pension and Other Postretirement Plans	203,326,221	188,801,133	Various	203,978,173	188,149,181
25						
26	Ohio Green Power Pricing Program	185,171	20,858			206,029
27	-Docket No 06-1153-EL-UNC					
28						
29	Carrying Chgs-Deferred Storm Exp-Hurrican Ike	96,730	575,324	421	4,183	667,871
30	Ohio Wind Storm - Case No. 08-1301-EL-AAM					
31						
32	Carrying Charges-Ohio Fuel Adjustment Clause		20,199,917	421	5,760,202	14,439,715
33	- Ohio ESP - Case No. 08-918-EL-SSO					
34						
35	EDR Deferral		5,032,690	182.3	3,407,531	1,625,159
36	- EDR - Economic Development Rider					
37	- Case No. 09-119-EL-AEC					
38						
39	EDR Carrying Charges		7,660			7,660
40	- EDR - Economic Development Rider					
41	- Case No. 09-119-EL-AEC					
42						
43						
44	TOTAL	445,237,298	1,003,714,055		710,314,246	738,637,107

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 2009/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

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

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Allowances	90,062	2,455,026	Various	2,244,664	300,424
2						
3	Deferred Property Taxes	96,831,588	98,588,772	Various	91,484,436	103,935,924
4						
5	Cook Coal Terminal - Opr Exp	288,930	5,214,522	930.2	5,061,031	442,421
6						
7	Real Estate Subsidence	728,150				728,150
8						
9	Agency Fees - Factored A/R	2,762,038	32,303,839	Various	31,846,343	3,219,534
10						
11	Defrd Property Tax - Cap Leases	53,500	566,750	408.1	561,750	58,500
12						
13	Labor Accruals	2,659,584	11,140,541	Various	13,800,125	
14						
15	Gavin JMG LT Prepaid Exp	12,112,895	93,904,069	165, 507	106,016,964	
16						
17	Defrd Cook Coal Term Lease Exp	281,376		931	46,896	234,480
18						
19	Def Exp Selling Price Variance	8,601	73,350	930.2	8,601	73,350
20						
21	NonTradition Option Premium		1,298,351	232	1,225,603	72,748
22						
23	Unamortized Credit Line Fees	438,763		431	172,395	266,368
24						
25	Deferred Expenses - Current	131,258	7,967,261	Various	8,094,954	3,565
26						
27	Deferred Contract Expenses	978,086	1,779,357	Various	2,757,443	
28						
29	SCR Catalyst Modules	20,400				20,400
30						
31	Def Lease Assets - Non Taxable		5,708,899	Various	5,650,698	58,201
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress	2,144,281				1,803,992
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	119,529,512				111,218,057

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Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

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

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	Contributions in Aid of Construction	14,393,309	12,474,927
3	Accrued Book ARO Expense - SFAS 143	31,260,752	32,977,446
4	Deferred State Income Taxes	7,848,041	25,655,993
5	Interest Expense Capitalized for Tax	50,660,020	55,507,273
6			
7	Other	114,036,736	44,071,557
8	TOTAL Electric (Enter Total of lines 2 thru 7)	218,198,858	170,687,196
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	103,890,301	99,694,282
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	322,089,159	270,381,478

Notes

	(b)	(c)
Nonutility Items - 190.2	21,807,152	20,920,027
SFAS 109	7,669,364	7,727,896
SFAS 87	73,979,043	70,142,037
SFAS 133	434,742	904,322
Total Line 17	103,890,301	99,694,282

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

Balance at Beginning of Year	$322,089,159
(Less) Amounts Debited to:	
(a) Account 410.1	(112,449,451)
(b) Account 410.2	(2,809,581)
(c) Various	(93,865,401)
(Plus) Amounts Credited to:	
(a) Account 409.3	0
(b) Account 411.1	76,291,769
(c) Account 411.2	1,922,455
(d) Various	79,202,528
Balance at End of Year	$270,381,478

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 2009/Q4

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Common Stock	40,000,000		
2				
3	Total Common	40,000,000		
4				
5	Preferred Stock:			
6	Cumulative Preferred $100 Par	3,762,403		
7	4.08 % Series		100.00	103.00
8	4.20% Series		100.00	103.20
9	4.40% Series		100.00	104.00
10	4.50% Series		100.00	110.00
11				
12				
13	Cumulative Preferred - $25 Par (A)	4,000,000		
14				
15	Total Preferred	7,762,403		
16				
17	(A) Authorized but not issued.			
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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 2009/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
						5
						6
14,595	1,459,500					7
22,824	2,282,400					8
31,482	3,148,200					9
97,363	9,736,300					10
						11
						12
						13
						14
166,264	16,626,400					15
						16
						17
						18
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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 2009/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	
2		
3	Prior to 2009 - Parent company contributions	531,035,096
4	2009 Parent company contributions	550,000,000
5		
6	Subtotal	1,081,035,096
7		
8		
9	209 - Reduction in Par or Stated Value of Capital Stock	
10		
11		
12	210 - Gain on Resale or Cancellation of Reacquired Capital Stock	
13		
14	Beginning Balance	3,317,447
15	4.50% Series - Gain on Redemption of 10 shares	391
16		
17		
18	Subtotal	3,317,838
19		
20	211 - Miscellaneous Paid-in Capital	
21		
22	Recorded in connection with merger of Central Ohio Light and	
23	Power Company with respondent in 1955	168,748
24	Overestimated costs of financing	196,599
25	Preferred Stock redemption gains due to implemention of SFAS 150	1,193,926
26	Recorded in connection with merger of JMG with respondent in 2009	36,509,286
27	Subtotal	38,068,559
28		
29		
30		
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37		
38		
39		
40	TOTAL	1,122,421,493

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 2009/Q4

CAPITAL STOCK EXPENSE (Account 214)

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

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1		
2		
3		
4		
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11		
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21		
22	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 2009/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 221 - Bonds:		
2	----------		
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	Ohio Air Quality Development Series 2005A, Variable Rate Due 01/2029	-54,500,000	
10			
11	Ohio Air Quality Development Series 2005B, Variable Rate Due 07/2028	-54,500,000	
12			
13	Marshall County Series E Bonds, Variable Rate Due 06/2022	-50,000,000	
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	Total FERC 222:	-303,000,000	
20			
21	Fixed Rate Promissory Notes Payable to Parent		
22	5.250% Due 06/2015	200,000,000	
23			
24	Total FERC 223:	200,000,000	
25			
26	Account 224 - Other Long-Term Debt		
27	----------		
28	Installment Purchase Contracts:		
29	----------		
30	Marshall County Series F, Variable Rate Due 04/2022	35,000,000	163,995
31			
32	Marshall County Series E, Variable Rate Due 06/2022	50,000,000	425,000
33	TOTAL	3,248,580,000	31,940,800

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 2009/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			
2	Ohio Air Quality:		
3			
4	Ohio Air Quality Series C, 5.150% Due 05/2026	50,000,000	998,500
5			
6	Ohio Air Quality Development Series 1997A, 5.625% Due 10/2022	19,565,000	
7			
8	West Virginia Economic Development Mitchell Series 2008A, Variable Rate Due 4/2036	65,000,000	332,083
9			
10	Ohio Air Quality Development Series 1997B, 5.625% Due 01/2023	19,565,000	
11			
12	Mitchell Series 2007A, 4.90% Due 6/2037	65,000,000	581,256
13			
14	Ohio Air Quality Development Series 2005A, Variable Rate Due 01/2029	54,500,000	300,438
15			
16	Ohio Air Quality Development Series 2005B, Variable Rate Due 07/2028	54,500,000	300,438
17			
18	Ohio Air Quality Development Series 2005C, Variable Rate Due 04/2028	54,500,000	300,437
19			
20	Ohio Air Quality Development Series 2005D, Variable Rate Due 10/2028	54,500,000	300,437
21			
22	West Virginia Economic Development Sporn Series 2008C, Variable Rate Due 7/2014	50,000,000	273,786
23			
24	Ohio Air Quality Development Cardinal Series 2008A, 7.125% Due 6/1/2041	79,450,000	967,368
25	Bond subject to Mandatory Tender for purchase (puttable) 06/01/2010		
26			
27	West Virginia Economic Development Kammer Series 2008B, Variable Rate Due 07/2014	50,000,000	282,353
28			
29	Brokerage Fees on Auction Rate Notes		
30	Letter of Credit Fees associated with Variable Rate Demand Notes		
31			
32	Subtotal	701,580,000	5,226,091
33	TOTAL	3,248,580,000	31,940,800

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 2009/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			
2	Unsecured Medium Term Notes		
3	5.500% Due 02/2013	250,000,000	1,805,904
4			647,500 D
5			
6	5.750% Due 09/2013	250,000,000	1,676,238
7			200,000 D
8			
9	6.600% Due 02/2033	250,000,000	2,368,087
10			1,165,000 D
11			
12	4.850% Due 01/2014	225,000,000	1,697,821
13			184,500 D
14			
15	Variable Rate Due 04/2010	400,000,000	1,551,918
16			
17	6.375% Due 07/2033	225,000,000	2,204,350
18			1,845,000 D
19			
20	Senior Note, Series M, 5.375% Due 10/2021	500,000,000	3,725,000
21	Application to The Public Utilities Commission of Ohio		2,065,000 D
22	Case #09-313-EL-AIS, dated 06/17/09		
23	Amortization of Cash Flow Hedge on 5.375% SUN		
24	Settled Cash Flow Hedge on 5.375% SUN - Ineffective Portion		
25			
26	5.300% Due 11/2010	200,000,000	1,623,319
27			270,000 D
28	Amortization of Cash Flow Hedge on 5.300% SUN		
29			
30	6.000% Due 06/2016	350,000,000	2,449,572
31			1,235,500 D
32	Amortization of Cash Flow Hedge on 6.000% SUN		
33	TOTAL	3,248,580,000	31,940,800

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 2009/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			
2	Subtotal:	2,650,000,000	26,714,709
3			
4	Subtotal:		
5			
6	Total FERC 224:	3,351,580,000	31,940,800
7			
8	Total FERC 224:		
9			
10	See Footnote		
11			
12			
13			
14			
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	3,248,580,000	31,940,800

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 2009/Q4

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

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
						3
						4
						5
						6
05/05/08	04/01/22			-35,000,000	-243,821	7
						8
01/21/05	01/01/29			-54,500,000	-12,841	9
						10
01/21/05	07/01/28			-54,500,000	-12,841	11
						12
05/05/08	06/01/22			-50,000,000	-482,752	13
						14
01/21/05	04/01/28			-54,500,000	-12,841	15
						16
01/21/05	10/01/28			-54,500,000	-12,841	17
						18
				-303,000,000	-777,937	19
						20
						21
02/05/04	06/01/15			200,000,000	10,500,000	22
						23
				200,000,000	10,500,000	24
						25
						26
						27
						28
						29
07/29/05	04/01/22	07/29/05	04/01/22	35,000,000	243,821	30
						31
12/17/03	06/01/22	12/17/03	06/01/22	50,000,000	482,752	32
				3,248,580,000	129,578,994	33

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 2009/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.
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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
05/13/99	05/01/26	05/01/99	05/01/26	50,000,000	2,575,000	4
						5
12/03/97	10/01/22			19,565,000	48,913	6
						7
06/05/08	04/01/36	06/05/08	04/01/36	65,000,000	222,371	8
						9
12/03/97	01/01/23			19,565,000	48,912	10
						11
06/13/07	06/01/37	06/13/07	06/01/37	65,000,000	3,185,000	12
						13
01/21/05	01/01/29	01/21/05	08/18/09	54,500,000	12,841	14
						15
01/21/05	07/01/28	01/21/05	09/08/09	54,500,000	12,841	16
						17
01/21/05	04/01/28	01/21/05	09/01/09	54,500,000	12,841	18
						19
01/21/05	10/01/28	01/21/05	08/11/09	54,500,000	12,841	20
						21
06/23/08	07/01/14	06/23/08	07/01/14	50,000,000	175,890	22
						23
12/18/08	06/01/41	12/18/08	06/01/10	79,450,000	5,660,813	24
						25
						26
06/23/08	07/01/14	06/23/08	07/01/14	50,000,000	175,466	27
						28
					211,521	29
					839,025	30
						31
				701,580,000	13,920,848	32
				3,248,580,000	129,578,994	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

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						1
						2
02/14/03	02/15/13	02/14/03	02/15/13	250,000,000	13,750,000	3
						4
						5
09/09/08	09/11/13	09/09/08	09/11/13	250,000,000	14,375,000	6
						7
						8
02/14/03	02/15/33	02/14/03	02/15/33	250,000,000	16,500,000	9
						10
						11
07/11/03	01/15/14	07/11/03	01/15/14	225,000,000	10,912,500	12
						13
						14
04/05/07	04/05/10	04/05/07	04/05/10	400,000,000	4,398,705	15
						16
07/11/03	07/15/33	07/11/03	07/15/33	225,000,000	14,343,750	17
						18
						19
09/24/09	10/01/21	09/24/09	10/01/21	500,000,000	7,241,319	20
						21
						22
					-489,769	23
					-6,415,613	24
						25
11/16/05	11/01/10	11/16/05	11/01/10	200,000,000	10,600,000	26
						27
					138,641	28
						29
06/12/06	06/01/16	06/12/06	06/01/16	350,000,000	21,000,000	30
						31
					-418,450	32
				3,248,580,000	129,578,994	33

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Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

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

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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
				2,650,000,000	105,936,083	2
						3
						4
						5
				3,351,580,000	119,856,931	6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
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						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
				3,248,580,000	129,578,994	33

FOOTNOTE DATA

Schedule Page: 256.1 Line No.: 6 Column: a

Issuance: 5.625%, Ohio Air Quality Development, Series1997A, Due 2022
Principal Amount: $19,565,000
Date of JMG Transfer: 12/15/2009
- Interest for the year in column (i) is calculated from the date of JMG Transfer.

Schedule Page: 256.1 Line No.: 10 Column: a

Issuance: 5.625%, Ohio Air Quality Development, Series1997B, Due 2023
Principal Amount: $19,565,000
Date of JMG Transfer: 12/15/2009
- Interest for the year in column (i) is calculated from the date of JMG Transfer.

Schedule Page: 256.1 Line No.: 14 Column: a

Issuance: Variable Rate, Ohio Air Quality Development, Series 2005A, Due 2029
Principal Amount: $54,500,000
Date of JMG Transfer: 12/15/2009
Date of Reacquisition: 8/18/2009
- Unamortized expense, premium or discount expensed at date of reacqusition.
- Interest for the year in column (i) is calculated from the date of JMG Transfer.

Schedule Page: 256.1 Line No.: 16 Column: a

Issuance: Variable Rate, Ohio Air Quality Development, Series 2005B, Due 2028
Principal Amount: $54,500,000
Date of JMG Transfer: 12/15/2009
Date of Reacquisition: 9/8/2009
- Unamortized expense, premium or discount expensed at date of reacqusition.
- Interest for the year in column (i) is calculated from the date of JMG Transfer.

Schedule Page: 256.1 Line No.: 18 Column: a

Issuance: Variable Rate, Ohio Air Quality Development, Series 2005C, Due 2028
Principal Amount: $54,500,000
Date of JMG Transfer: 12/15/2009
Date of Reacquisition: 9/1/2009
- Unamortized expense, premium or discount expensed at date of reacqusition.
- Interest for the year in column (i) is calculated from the date of JMG Transfer.

Schedule Page: 256.1 Line No.: 20 Column: a

Issuance: Variable Rate, Ohio Air Quality Development, Series 2005D, Due 2028
Principal Amount: $54,500,000
Date of JMG Transfer: 12/15/2009
Date of Reacquisition: 8/11/2009
- Unamortized expense, premium or discount expensed at date of reacqusition.
- Interest for the year in column (i) is calculated from the date of JMG Transfer.

Schedule Page: 256.1 Line No.: 24 Column: g

Ohio Air Quality Development Cardinal Bond 7.125%, Series 2008A has a Mandatory Tender Date (PUT Date) of 06/01/10.

Schedule Page: 256.3 Line No.: 10 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 and interest of $196,008 on reallocated off-system sales margins between the AEP East and West companies as ordered by FERC.

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 2009/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)	306,572,997
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	-480,790,015
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		306,573
Federal Income Taxes		155,287
State Income Taxes		7,332
Pretax Book Income		469,192
Increase (Decrease) in Taxable Income resulting from:		
Allowance for Funds Used During Construction and Other Differences Between Items Capitalized for Books and Expensed for Tax		1,012
Amortization of Pollution Control Equip		(111,928)
Emission Allowances (Net)		(5,279)
Excess Tax Vs Book Depreciation		(61,961)
Mark-to-Market		(36,591)
Provision for Workers' Compensation		304
Pension Expenses (Net)		7,913
RTO Expenses and Carrying Charges		743
Removal Costs		(3,842)
Repair Allowance		(1,200)
Book/Tax Unit of Property Adj		(374,961)
Capitalized Relocation Costs		(1,500)
SFAS 106 - Post Retirement Benefit Expense Accrued/Funded (Net)		(1,115)
SFAS 112 - Post Employment Benefit Expense Accrued/Funded (Net)		99
Deferred State Income Tax - Expense and Interest		319
Accrued Taxes		1,641
Accrued ARO Expense - SFAS 143		7,462
Provision for Revenue Refunds		(63,813)
Regulatory Liabilities - Unused Shopping Incentives		(669)
Regulatory Assets - Deferred Equity Carrying Charges		16,559
Regulatory Assets - Extension of Local Facilities		(10,453)
Regulatory Assets - Defd Transmission Carrying Costs		(3,346)
Regulatory Assets - Under Recovery - Ohio TCR Rider		4,839
Federal & State Mitigation Programs		(2,098)
Deferred Storm Damage		306
Deferred Book Gain-Fuel Contract Termination		(7,309)
Deferred Fuel Costs		(312,010)
Equity in Subsidiaries		(7,130)
Accrued Low Income Housing Obligations		4,183
Bk Deferral - Demand Side Mgmt Expense		(4,007)
Charitable Contribution Carryforward		2,550
Cust Adv Inc for Tax		(3,975)
Other (Net)		(1,356)
Estimated Current Year Taxable Income Before State Income Tax (Separate Return Basis)		(497,421)
Less State Income Tax		(16,631)
Federal Taxable Income		(480,790)
		=======
Computation of Tax *		
Federal Income Tax on Current Year Taxable Income (Separate Return Basis) at the Statutory Rate of 35%		(168,276)
Adjustment due to System Consolidation	(a)	0
Estimated Tax Currently Payable	(b)	(168,276)
Tax Provision Adjustment		(1,683)
Adjustments of Prior Year's Accruals (Net)		(21,568)
Estimated Current Federal Income Taxes (Net)		(191,527)
		=======

FOOTNOTE DATA

(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 2009 System Federal income taxes will not be available until the consolidated Federal income tax return is completed and filed by September 2010. The actual allocation of the System consolidated Federal income tax to the members of the consolidated group will not be available until after the consolidated federal income tax return is filed.

Name of Respondent	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 2009/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	FEDERAL:					
2	INCOME TAX	-8,704,132		-189,804,084	-65,358,086	4,762,716
3	FICA - 2009	1,839,389		10,849,169	11,865,831	
4	Unemployment - 2009	75,293		72,403	124,202	
5	EXCISE TAX - 2008			6,953	6,953	
6	EXCISE TAX - 2009			52,525	52,525	
7	MISC - LIC/RGSTRTION			37,350	37,055	-295
8	STATE OF OHIO					
9	INCOME TAX 2007 & PRIOR					
10	INCOME TAX - 2008			-428,919	-428,919	
11	INCOME TAX - 2009					
12	Fran Tax - 2008 & Prior					
13	Fran Tax - 2009			30,000	30,000	
14	CAT TAX - 2008	902,503		46,993	949,496	
15	CAT TAX - 2009			4,921,500	3,621,497	
16	OCC & PUCO FEES - 2009			2,719,778	2,719,778	
17	KWH State Excise Tax - 2008	7,070,576			7,070,576	
18	KWH State Excise Tax - 2009			73,322,711	66,740,301	
19	SALES & USE - 2008	245,020	113,254	-159,726	-27,960	
20	SALES & USE - 2009			966,149	787,482	
21	SALES & USE - Audit Prov	435,000				
22	Unemployment - OH 2009	108,039		142,079	216,266	
23	STATE OF ILLINOIS					
24	INCOME TAX 2007 & Prior					
25	INCOME TAX 2008	-29,954		-4,524	-30,253	4,225
26	INCOME TAX 2009			-151,139	46,518	
27	SALES & USE - 2008	5,922		661	6,583	
28	SALES & USE - 2009			96,463	91,982	
29	Unemployment - IL 2009	2,183		5,243	6,572	
30	STATE OF LOUISIANA					
31	STATE FRAN - 2007					
32	STATE FRAN - 2008					
33	STATE OF WEST VIRGINIA:					
34	INCOME TAX - 2007&PRIOR	-5,060,810		-7,635,510	-12,281,387	
35	INCOME TAX - 2008	562,089		-10,646,167	-10,084,078	
36	INCOME TAX - 2009			-6,266,474	6,053,650	
37	STATE FRAN. 2007&PRIOR	-572,966			-1,582,676	
38	STATE FRAN. 2008	-129,807		-83,655	-213,462	
39	STATE FRAN. 2009			18,300	26,900	
40	Unemployment - WV 2009	22,192		55,333	70,916	
41	TOTAL	186,717,476	113,254	-11,575,708	114,553,169	4,557,293

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Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/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	SALES & USE TAX - 2008	44,683		-5,461	39,222	
2	SALES & USE TAX -2009			197,530	121,425	
3	BUS & OCCUPATION-2008	920,684		255,136	1,175,820	
4	BUS & OCCUPATION-2009			16,091,873	14,761,056	
5	BUS & OCCUPATION-Audit			2,757,500		
6	Local					
7	Real & Pers-2007 OH	73,059,880		40,898	73,100,778	
8	Real & Pers-2008 OH	77,557,644				
9	Real & Pers-2009 OH			82,581,705	3,355	
10						
11	Re Prop-Leased 2007 OH	8,196		-8,196		
12	Re Prop-Leased 2008 OH	188,480		-8,344	180,136	
13	Re Prop-Leased 2009 OH			169,158		
14						
15	Pers Prop-Leased 2005 OH	98,656				
16	Pers Prop-Leased 2006 OH	277,277		-77,455	199,822	
17	Pers Prop-Leased 2007 OH	280,020		54,012	334,032	
18	Pers Prop-Leased 2008 OH	401,020		-42,227	358,793	
19	Pers Prop-Leased 2009 OH			440,000		
20						
21	RE & Pers Prop-2006 WV					
22	RE & Pers Prop-2007 WV	5,752,872		202	5,753,074	
23	RE & Pers Prop-2008 WV	13,329,086		141,480	6,739,364	
24	RE & Pers Prop-2009 WV			14,439,971		
25	Pers Prop-Leased 2006 WV					
26	Pers Prop-Leased 2007 WV	58,438		2,809	61,247	
27	Pers Prop-Leased 2008 WV	107,000		-43,274	33,936	
28	Pers Prop-Leased 2009 WV			117,000		
29	RE & Pers Prop-2007 IL					
30	RE & Pers Prop-2008 IL	660,165			598,560	-61,605
31	RE & Pers Prop-2009 IL					630,000
32						
33	RAIL CAR PROPERTY					
34	Prop Tax -2006					
35	Prop Tax - 2007	93,951		1,577	95,528	
36	Prop Tax - 2008	152,571		48,380	98,868	
37	Prop Tax - 2009			137,647		
38	Real Prop Taxes					
39	2008 LA			4,606	4,606	
40	2009 LA			1,640	1,640	
41	TOTAL	186,717,476	113,254	-11,575,708	114,553,169	4,557,293

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 2009/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	2008 KY			4,501	4,501	
3						
4						
5	CITY TAX - 2007 & PRIOR			85,969	85,969	
6	CITY TAX - 2008	-378,568		-153,580	-532,148	
7	CITY TAX - 2009			-1,557,392	693,773	
8	Multi Fran Tax - 2000	4,131,739		-2,753,672		-305,336
9	Multi Income Tax - 2000					
10	FED INC TAX FIN48	2,531,840		-1,592,992		-963,509
11	STATE INC TAX LONG	10,497,714		-1,116,767		491,097
12	OTH TAX PAYABLE-IRS	130,000		-130,000		
13	STATE OF MICHIGAN					
14	INCOME TAX 2008	43,591		166,096	209,687	
15	INCOME TAX 2009			10,000	-88,687	
16	VARIOUS STATE			550	550	
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	186,717,476	113,254	-11,575,708	114,553,169	4,557,293

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 2009/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
-128,387,414		-197,923,979			8,119,895	2
822,727		7,789,730			3,059,439	3
23,494		44,899			27,504	4
					6,953	5
		29,835			22,690	6
		37,327			23	7
						8
						9
		-482,625			53,706	10
						11
						12
		30,293			-293	13
		46,993				14
1,300,003		4,921,500				15
		2,719,778				16
						17
6,582,410		73,322,711				18
		880			-160,606	19
257,293	78,626	3,628			962,521	20
435,000						21
33,852		82,964			59,115	22
						23
						24
		-15,731			11,207	25
-197,657		-169,362			18,223	26
					661	27
4,481					96,463	28
854					5,243	29
						30
						31
						32
						33
-414,933		-7,635,510				34
		-10,735,437			89,270	35
-12,320,124		-6,621,133			354,659	36
1,009,710						37
		-83,655				38
-8,600		18,350			-50	39
6,609		68,482			-13,149	40
65,111,264	78,626	-34,527,654			22,951,946	41

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 2009/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)	
					-5,461	1
76,105		8,423			189,107	2
		245,678			9,458	3
1,330,817		16,091,873				4
2,757,500		2,757,500				5
						6
		40,898				7
77,557,644		76,699,154			-76,699,154	8
82,578,350		2,053			82,579,652	9
						10
		-8,196				11
		-8,344				12
169,158		169,158				13
						14
98,656						15
		-77,455				16
		54,012				17
		-42,227				18
440,000		440,000				19
						20
						21
		4,725,436			-4,725,234	22
6,731,202		5,981,233			-5,839,753	23
14,439,971					14,439,971	24
						25
		2,809				26
29,790		10,226			-53,500	27
117,000		58,500			58,500	28
						29
						30
630,000						31
						32
						33
						34
					1,577	35
102,083		3,982			44,398	36
137,647					137,647	37
						38
					4,606	39
		1,640				40
65,111,264	78,626	-34,527,654			22,951,946	41

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 2009/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
					4,501	2
						3
						4
		85,969				5
		-153,920			340	6
-2,251,165		-1,650,023			92,631	7
1,072,731		-2,753,672				8
						9
-24,661		-1,592,992				10
9,872,044		-1,116,767				11
		-130,000				12
						13
		166,910			-814	14
98,687		10,000				15
		550				16
						17
						18
						19
						20
						21
						22
						23
						24
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						35
						36
						37
						38
						39
						40
65,111,264	78,626	-34,527,654			22,951,946	41

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

Adjustment (Debits)/Credits to Federal Income Tax Account 2360001

3,855,459 JMG Transfer to OPCO offset to Accounts Receivable 1460009

(56,252) offset to 1740011 Fuel Tax Credit

963,509 reclassed to 2360601

Schedule Page: 262 Line No.: 7 Column: f

Adjustment Debits to Misc - Lic/Registration Fees

(295) offset to Accounts Payable/Assoc Co 2340001

Schedule Page: 262 Line No.: 25 Column: f

Adjustment Credit to Illinois Income Tax 2008

4,225 offset to Penalties 4263001

Schedule Page: 262.1 Line No.: 30 Column: f

Eliminated in AEP Consolidation

Schedule Page: 262.1 Line No.: 31 Column: f

Eliminated in AEP Consolidation

Schedule Page: 262.2 Line No.: 8 Column: f

Adjustment Debit to Multi Fran Tax 2000

(305,336) offset to Interest 4310001

Schedule Page: 262.2 Line No.: 10 Column: f

Adjustment Debit to Fed Inc Tax Long Term

(963,509) reclassed from 2360001 Federal Income Tax

Schedule Page: 262.2 Line No.: 11 Column: f

Adjustment Credit to State Inc Tax Long Term

491,097 reclassed from 236001200

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 2009/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%						
3	4%	2,378			4114	2,378	
4	7%						
5	10%	2,914,572			4114/4115	947,074	
6							
7							
8	TOTAL	2,916,950				949,452	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
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48							

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 2009/Q4

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
	Various		3
			4
1,967,498	Various		5
			6
			7
1,967,498			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
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			45
			46
			47
			48

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 2009/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		253	28,369	967,329	938,960
2						
3	Deferred Revenues	5,812,584	151	7,309,379	1,496,795	
4	- Peabody Coal Contract Term.					
5						
6	Allowances	336,250	Various	26,188,729	26,851,950	999,471
7						
8	Customer Advance Receipts	8,905,730	142	83,400,618	79,425,146	4,930,258
9						
10	Deferred Rev - Pole Attachments	574,371	Various	1,597,280	1,734,865	711,956
11						
12	IPP - System Upgrade	2,464,505	431	1		2,464,504
13						
14	ABD - Sharyland Deferred Revenue				496,916	496,916
15						
16	Unidentified Cash Receipts	283	Various	18,488	27,340	9,135
17						
18	Railroad Cars Subleased Rev	64,734	Various	3,590,727	3,526,646	653
19						
20	Accrued Lease Exp - Non Current	889,745	931	146,244		743,501
21						
22	Other Deferred Credits - Current	12,931,143	Various	29,432,925	28,839,052	12,337,270
23						
24	State Mitigation Deferral (NSR)	3,220,848	242	1,073,616		2,147,232
25						
26	Federal Mitigation Deferral (NSR)	5,360,028	242	664,300		4,695,728
27						
28	Fiber Opt Lines Sold Deferred Rev	75,408	451	5,127		70,281
29	- Amortization period - 1/2005 to					
30	12/2024					
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	40,635,629		153,455,803	143,366,039	30,545,865

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 2009/Q4

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

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities	192,655,821	49,045,679	7,230,641
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	192,655,821	49,045,679	7,230,641
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)	192,655,821	49,045,679	7,230,641
18	Classification of TOTAL			
19	Federal Income Tax	192,655,821	49,045,679	7,230,641
20	State Income Tax			
21	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 2009/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		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)	(k)	
							1
							2
							3
						234,470,859	4
							5
							6
							7
						234,470,859	8
							9
							10
							11
							12
							13
							14
							15
							16
						234,470,859	17
							18
						234,470,859	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 2009/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)	Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	687,189,585	243,192,698	65,317,939
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	687,189,585	243,192,698	65,317,939
6				
7	Non Utility	2,044,673		
8	SFAS 109/FIN 48	103,876,668		
9	TOTAL Account 282 (Enter Total of lines 5 thru	793,110,926	243,192,698	65,317,939
10	Classification of TOTAL			
11	Federal Income Tax	793,110,926	243,192,698	65,317,939
12	State Income Tax			
13	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 2009/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
				Various	24,678,839	889,743,183	2
							3
							4
					24,678,839	889,743,183	5
							6
3,956						2,048,629	7
		Various	42,652,663	Various	39,066,469	100,290,474	8
3,956			42,652,663		63,745,308	992,082,286	9
							10
3,956			42,652,663		63,745,308	992,082,286	11
							12
							13

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 2009/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)	Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Mark To Market Bk Gain-A/L-Tax	33,465,082	21,407,865	44,732,249
4	Accrued Bk Pension Expense	35,930,888	2,984,882	42,517,394
5	Capitalized Software Cost-Book	9,628,110	2,746,994	2,269,646
6	Deferred Fuel		109,203,512	
7	Deferred SIT - Normalized	37,195,565	35,157,431	127,356
8	Other	74,034,743	77,784,829	22,380,194
9	TOTAL Electric (Total of lines 3 thru 8)	190,254,388	249,285,513	112,026,839
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other SFAS 109 & 133 / NonUtil	76,239,693		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	266,494,081	249,285,513	112,026,839
20	Classification of TOTAL			
21	Federal Income Tax	216,602,465	214,128,082	111,899,483
22	State Income Tax	49,891,617	35,157,431	127,356
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 2009/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				Balance at End of Year	Line No.
		Debits		Credits			
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
						10,140,698	3
						-3,601,624	4
						10,105,458	5
						109,203,512	6
				Various	1,077,196	73,302,836	7
		Various	11,731,000	Various	1	117,708,379	8
			11,731,000		1,077,197	316,859,259	9
							10
							11
							12
							13
							14
							15
							16
							17
889,198	12,092,838	Various	57,342,165	Various	64,340,297	72,034,185	18
889,198	12,092,838		69,073,165		65,417,494	388,893,444	19
							20
889,198	12,092,838		68,854,383		61,257,856	300,030,897	21
			218,782		4,159,637	88,862,547	22
							23

NOTES (Continued)

FOOTNOTE DATA

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

Line 18 Other - Detail

	Balance at Beginning of Year	Balance at End of Year
Non-Utility 283.2	(310,116)	(11,513,756)
SFAS 109	74,149,823	76,286,720
SFAS 133	2,399,986	7,261,221
Total	$ 76,239,693	$ 72,034,185

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 2009/Q4

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Unrealized Gain on Forward Commitments	4,319,108	175	14,846,225	10,527,117	
2						
3	Ohio RSP-Low Income Customer/Econ Recovery	1,779,652	232	1,169,189	500,000	1,110,463
4	-Docket No. 04-169-EL-UNC					
5						
6	Over-Recovered Ohio TCR Rider		182.3, 447	30,290,053	40,293,545	10,003,492
7	-Docket No. 05-1194-EL-UNC					
8						
9	Carry Chg-Over Recover OH TCR		182.3, 431	600,117	776,927	176,810
10	-Docket No. 05-1194-EL-UNC					
11						
12	IGCC Pre-Construction Costs Net Recovery	1,362,913	182.3	8,343	152	1,354,722
13	-Docket No. 05-376-EL-UNC					
14						
15	Over-Recovered ESRP Costs		593	1,847,953	2,968,797	1,120,844
16	- ESRP - Enhanced Service Reliability Plan					
17	- Ohio ESP - Case No. 08-918-EL-SSO					
18						
19	SFAS 109 Deferred FIT	4,518,643	Various	922,884	6,914	3,602,673
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	11,980,316		49,684,764	55,073,452	17,369,004

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 2009/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	637,838,015	602,770,227
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	424,982,285	402,149,196
5	Large (or Ind.) (See Instr. 4)	609,914,643	696,187,169
6	(444) Public Street and Highway Lighting	10,108,144	9,406,473
7	(445) Other Sales to Public Authorities	31,587	32,865
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	1,682,874,674	1,710,545,930
11	(447) Sales for Resale	1,294,210,711	1,427,238,045
12	TOTAL Sales of Electricity	2,977,085,385	3,137,783,975
13	(Less) (449.1) Provision for Rate Refunds		42,435,298
14	TOTAL Revenues Net of Prov. for Refunds	2,977,085,385	3,095,348,677
15	Other Operating Revenues		
16	(450) Forfeited Discounts	1,124,119	1,107,361
17	(451) Miscellaneous Service Revenues	2,918,918	2,732,594
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	12,308,223	12,883,329
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	2,707,743	9,058,778
22	(456.1) Revenues from Transmission of Electricity of Others	16,572,402	17,659,389
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	35,631,405	43,441,451
27	TOTAL Electric Operating Revenues	3,012,716,790	3,138,790,128

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 2009/Q4

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
7,338,988	7,527,989	607,807	609,365	2
				3
5,685,770	5,823,797	92,567	92,205	4
11,834,235	14,441,162	7,244	7,310	5
76,838	77,966	2,517	2,541	6
548	626	26	26	7
				8
				9
24,936,379	27,871,540	710,161	711,447	10
28,352,569	32,475,287	105	109	11
53,288,948	60,346,827	710,266	711,556	12
				13
53,288,948	60,346,827	710,266	711,556	14

Line 12, column (b) includes $ 27,225 of unbilled revenues.

Line 12, column (d) includes 5,855,328 MWH relating to unbilled revenues

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

Detail of Unmetered Sales:

	Revenue	MWH	Average Customers
Residential	3,289,020	14,688	22,983
Commercial	6,082,840	39,734	15,303
Industrial	952,840	6,392	1,197
Public Street Lighting	9,240,028	68,095	1,288
	19,564,728	128,909	40,771

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 2009
Financial Trading Revenues Unrealized	$ (8,911,477)
MTM Coal Procurement	$ 2,238,968
MTM Emissions Compliance	$ 761,250
Coal Trading Realized Gain/Loss	$ 4,701,279
Deferred Return - Ohio Line Extension Construction	$ 2,496,147
Other Electric Rev - Associated Business Development	$ 938,560
Oth Elect Rev-Coal Preparation	$ 505,832
All Other (under $250,000 each)	$ (22,816)
Total	**$ 2,707,743**

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 2009/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					
18					
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25					
26					
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35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	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 2009/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	RS Residential Service	7,343,232	631,426,013	607,399	12,090	0.0860
3	RS-ES Res Energy Storage	8,711	634,125	370	23,543	0.0728
4	RS-TOD Res Time of Day	699	57,119	38	18,395	0.0817
5	GS-1 Gen Svc-Non-Demand Meter	11	1,060			0.0964
6	OL Outdoor Lighting	14,688	3,289,020			0.2239
7	Subtotal-Billed	7,367,341	635,407,337	607,807	12,121	0.0862
8	Net Unbilled	-28,353	2,430,678			-0.0857
9	Total-Residential	7,338,988	637,838,015	607,807	12,075	0.0869
10						
11	442-Commercial					
12	RS Residential Service	1	202			0.2020
13	GS-1 Gen Svc-Non-Demand Meter	350,380	35,382,640	59,676	5,871	0.1010
14	GS-2 Gen Svc-Low Load Factor	2,205,509	182,111,467	26,434	83,435	0.0826
15	GS-3 Gen Svc-Med/High Load	2,912,715	186,760,094	5,068	574,727	0.0641
16	GS-TOD Gen Svc-Time of Day	96,813	6,758,084	704	137,518	0.0698
17	SBS Standby Service	667	193,254	1	667,000	0.2897
18	OL Outdoor Lighting	37,896	5,911,123			0.1560
19	EHG Electric Heating General	23,040	1,659,933	489	47,117	0.0720
20	SS School Service	49,759	3,704,176	195	255,174	0.0744
21	Net Estimated Billings	-100	-14,994			0.1499
22	Subtotal-Billed	5,676,680	422,465,979	92,567	61,325	0.0744
23	Net Unbilled	9,090	2,516,306			0.2768
24	Total-Commercial	5,685,770	424,982,285	92,567	61,423	0.0747
25						
26						
27	442-Industrial					
28	GS-1 Gen Svc-Non-Demand Meter	17,676	1,961,884	3,978	4,443	0.1110
29	GS-2 Gen Svc-Low Load Factor	964,132	76,790,212	2,520	382,592	0.0796
30	GS-3 Gen Svc-Med/High Load	3,090,615	195,619,223	654	4,725,711	0.0633
31	GS-4 General Service-Large	5,610,659	240,616,789	39	143,863,051	0.0429
32	GS-TOD Gen Svc-Time of Day	7,612	568,320	29	262,483	0.0747
33	OL Outdoor Lighting	6,371	950,910			0.1493
34	EHG Electric Heating General	1,116	91,150	18	62,000	0.0817
35	IRP-D Interruptible Power Discret	787,121	29,148,544	4	196,780,250	0.0370
36	IRP-D Special Contract	1,415,713	65,672,248	2	707,856,500	0.0464
37	Net Estimated Billings	-58,789	-2,403,400			0.0409
38	Subtotal-Billed	11,842,226	609,015,880	7,244	1,634,763	0.0514
39	Net Unbilled	-7,991	898,763			-0.1125
40	Total-Industrial	11,834,235	609,914,643	7,244	1,633,660	0.0515
41	TOTAL Billed	24,963,604	1,677,019,346	710,161	35,152	0.0672
42	Total Unbilled Rev.(See Instr. 6)	-27,225	5,855,328	0	0	-0.2151
43	TOTAL	24,936,379	1,682,874,674	710,161	35,114	0.0675

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 2009/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						
2	444-Street & Highway Lighting					
3	GS-1 Gen Svc-Non-Demand Meter	6,805	733,005	1,507	4,516	0.1077
4	GS-2 Gen Svc-Low Load Factor	1,837	146,865	26	70,654	0.0799
5	GS-3 Gen Svc-Med/High Load	1,060	70,480	2	530,000	0.0665
6	OL Outdoor Lighting	239	41,170			0.1723
7	SL Street Lighting	66,854	9,101,981	981	68,149	0.1361
8	SL Special Contract	13	5,155	1	13,000	0.3965
9	Subtotal-Billed	76,808	10,098,656	2,517	30,516	0.1315
10	Net Unbilled	30	9,488			0.3163
11	Total-St & Highway Lighting	76,838	10,108,144	2,517	30,528	0.1316
12						
13	A/C 445 Pub Authorities - Other					
14	Special Contracts	549	31,494	26	21,115	0.0574
15	Subtotal-Billed	549	31,494	26	21,115	0.0574
16	Net Unbilled	-1	93			-0.0930
17	Total-Pub Authorities - Other	548	31,587	26	21,077	0.0576
18						
19	Fuel Adj Clause - Footnote					
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	24,963,604	1,677,019,346	710,161	35,152	0.0672
42	Total Unbilled Rev.(See Instr. 6)	-27,225	5,855,328	0	0	-0.2151
43	TOTAL	24,936,379	1,682,874,674	710,161	35,114	0.0675

FOOTNOTE DATA

Schedule Page: 304.1 Line No.: 19 Column: a

Fuel Adjustment Clause - Total Estimated Additional Revenue Billed & Unbilled

440-Residential	**Revenues**
RS Residential Service	98,098,686
RS-ES Res Energy Storage	102,177
RS-TOD Res Time-of-Day	8,912
GS-1 Gen Svc-Non-Demand Meter	41
OL Outdoor Lighting	218,962
Subtotal-Billed	**98,428,778**
Net Unbilled	9,544,088
Total 440-Residential	**107,972,866**
442-Commercial	
RS Residential Service	12
GS-1 Gen Svc-Non-Demand Meter	4,649,928
GS-2 Gen Svc-Low Load Factor	30,498,241
GS-3 Gen Svc-Med/High Load Factor	42,417,561
GS-TOD Gen Svc-Time of Day	1,253,215
SBS Standby Service	107
OL Outdoor Lighting	567,194
EHG Electric Heating General	282,965
EHS Electric Heating Schools	5,465
SS School Service	645,523
Subtotal-Billed	**80,320,211**
Net Unbilled	6,230,799
Total 442-Commercial	**86,551,010**
442-Industrial	
GS-1 Gen Svc-Non-Demand Meter	245,653
GS-2 Gen Svc-Low Load Factor	13,313,359
GS-3 Gen Svc-Med/High Load Factor	44,048,322
GS-4 General Service-Large	54,569,521
GS-TOD Gen Svc-Time of Day	114,737
OL Outdoor Lighting	94,907
EHG Electric Heating General	14,448
IRP-D Interruptible Power Discret	9,885,825
IRP-D Special Contract	18,025,764
Net Estimated Billings	18,759
Subtotal-Billed	**140,331,295**
Net Unbilled	5,103,389
Total 442-Industrial	**145,434,684**
444-Street & Highway Lighting	
GS-1 Gen Svc-Non-Demand Meter	93,944
GS-2 Gen Svc-Low Load Factor	23,078
GS-3 Gen Svc-Med/High Load Factor	15,708
OL Outdoor Lighting	3,510
SL Street Lighting	936,893
SL Special Contract	182
Subtotal-Billed	**1,073,315**
Net Unbilled	30,144
Total 444-Street & Highway Lighting	**1,103,459**
445- Pub Authorities-Other	
Special Contracts	5,659
Subtotal-Billed	**5,659**
Net Unbilled	708
Total 445- Pub Authorities-Other	**6,367**
Total Billed	**320,159,258**
Total Unbilled	**20,909,128**
TOTAL	**341,068,386**

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SALES FOR RESALE (Account 447)

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Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	OHIO EDISON COMPANY(217)	RQ	OPCO 99			
2	OHIO EDISON COMPANY(244)	RQ	OPCO 99			
3	WHEELING POWER COMPANY	RQ	OPCO 18			
4	CLEVELAND PUBLIC POWER	IF	Note 1			
5	NC ELECTRIC MEMBERSHIP CORP.	IF	Note 1			
6	TOWN OF FRONT ROYAL	IF	Note 1			
7	WOLVERINE POWER SUPPLY COOP	IF	Note 1			
8	CITY OF COLUMBUS	LF	Note 1			
9	NC ELECTRIC MEMBERSHIP CORP.	LF	Note 1			
10	CAROLINA POWER & LIGHT	LU	Note 1			
11	THE BOROUGH OF PITCAIRN, PA	SF	Note 1			
12	AEP SERVICE CORPORATION	OS	23			
13	AEP SERVICE CORPORATION	OS	20			
14	ALLEGHENY ENERGY SUPPLY CO LLC	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	ALLETE, INC. DBA MINNESOTA PWR	OS	Note 1			
2	AMEREN ENERGY MARKETING	OS	Note 1			
3	AMERICAN MUNICIPAL POWER-OHIO	OS	Note 1			
4	ASSOCIATED ELECT COOPERATIVE	OS	Note 1			
5	B.P. ENERGY COMPANY	OS	Note 1			
6	BALTIMORE GAS & ELECTRIC	OS	Note 1			
7	BARCLAYS BANK PLC	OS	Note 1			
8	BNP PARIBAS COMMODITY FUTURES	OS	Note 1			
9	BP AMOCO	OS	Note 1			
10	BUCKEYE POWER GENERATING, LLC	OS	Note 2			
11	BUCKEYE RURAL ELECTRIC ADMIN	OS	Note 1			
12	CALPINE POWER SERVICE COMPANY	OS	Note 1			
13	CAROLINA POWER & LIGHT	OS	Note 1			
14	CENTRAL ILLINOIS	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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	(a)	(b)	(c)	(d)	(e)	(f)
1	CENTRAL ILLINOIS PUBLIC SVC CO	OS	Note 1			
2	CHEVRON TEXACO	OS	Note 1			
3	CHEVRON USA INC	OS	Note 1			
4	CITADEL ENERGY PRODUCTS LLC	OS	Note 1			
5	CITADEL EQUITY FUND LTD.	OS	Note 1			
6	CITIGROUP ENERGY INC.	OS	Note 1			
7	CITIZENS ELECT CO & WELLSBOROUGH	OS	Note 1			
8	CITY OF COLUMBUS	OS	Note 1			
9	CITY OF DOWAGIAC, MI	OS	Note 1			
10	CITY OF LEBANON	OS	Note 1			
11	CITY OF NEW MARTINSVILLE	OS	Note 1			
12	CITY OF PHILIPPI, WEST VIRGINI	OS	Note 1			
13	CITY OF WESTERVILLE	OS	Note 1			
14	CLECO UTILITY GROUP LLC	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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1	COMMONWEALTH EDISON COMPANY	OS	Note 1			
2	CONOCO INC.	OS	Note 1			
3	CONSTELLATION ENGY COMMODITIES	OS	Note 1			
4	CORAL POWER LLC	OS	Note 1			
5	CREDIT SUISSE ENERGY	OS	Note 1			
6	DELAWARE ELECTRIC MUNICIPAL CO	OS	Note 1			
7	DELMARVA POWER & LIGHT	OS	Note 1			
8	DIRECT ENERGY BUSINESS, LLC	OS	Note 1			
9	DOMINION EQUIPMENT INC	OS	Note 1			
10	DP&L POWER SERVICES	OS	Note 1			
11	DTE ENERGY TRADING INC.	OS	Note 1			
12	DUKE ENERGY CAROLINAS, LLC	OS	Note 1			
13	DUKE ENERGY INDIANA, INC.	OS	Note 1			
14	DUKE ENERGY KENTUCKY, INC.	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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1	DUKE ENERGY TRADING	OS	Note 1			
2	DUQUESNE POWER, L.P.	OS	Note 1			
3	DYNEGY POWER MARKETING INC.	OS	Note 1			
4	EAGLE ENERGY PARTNER I, L.P.	OS	Note 1			
5	EAST KY POWER CO-OP POWER MKTG	OS	Note 1			
6	EDF TRADING NORTH AMERICA LLC	OS	Note 1			
7	EDISON MISSION MKTG & TRADING	OS	Note 1			
8	ENDURE ENERGY, LLC	OS	Note 1			
9	ENERGY AMERICA, LLC	OS	Note 1			
10	ENG MKTG, DIV OF AMERADA HESS	OS	Note 1			
11	ENTERGY POWER SERV	OS	Note 1			
12	EXELON GENERATION - POWER TEAM	OS	Note 1			
13	FIRSTENERGY TRADING SERVICES	OS	Note 1			
14	FPL ENERGY POWER MARKETINGINC	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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1	GREAT RIVER ENERGY	OS	Note 1			
2	HARRISON RURAL ELECTRIFICATION	OS	Note 1			
3	HESS ENERGY TRADING COMPANY, L	OS	Note 1			
4	ILLINOIS MUNICIPAL ELEC AGENCY	OS	Note 1			
5	ILLINOIS POWER COMPANY	OS	Note 1			
6	INDIANA MUNICIPAL POWER AGENCY	OS	Note 1			
7	INTEGRYS ENERGY SERVICES, INC	OS	Note 1			
8	INTERSTATE POWER & LIGHT CO	OS	Note 1			
9	J ARON & COMPANY	OS	Note 1			
10	JP MORGAN VENTURES ENERGY CORP	OS	Note 1			
11	KANSAS CITY POWER & LIGHT CO	OS	Note 1			
12	KENTUCKY MUNICIPAL POWER AGNCY	OS	Note 1			
13	LEHMAN BROTHERS COMMODITY SVCS	OS	Note 1			
14	LETTERKENNY INDUSTRIL DEV AUTH	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)	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	LG&E UTILITIES POWER SALES	OS	Note 1			
2	LOUIS DREYFUS ENERGY SERV LP	OS	Note 1			
3	MERRILL LYNCH COMMODITIES, INC	OS	Note 1			
4	MICHIGAN PUBLIC POWER AGENCY	OS	Note 1			
5	MID CONTINENT CORP.	OS	Note 1			
6	MIDAMERICAN ENERGY	OS	Note 1			
7	MIDWEST ISO	OS	Note 1			
8	MIECO INC.	OS	Note 1			
9	MIZUHO SECURITIES USA INC	OS	Note 1			
10	MORGAN STANLEY CAPT.	OS	Note 1			
11	NC ELECTRIC MEMBERSHIP CORP.	OS	Note 1			
12	NEXTERA ENERGY POWER MKTG LLC	OS	Note 1			
13	NIPSCO ENERGY MANAGEMENT	OS	Note 1			
14	NORDIC ENERGY SERVICES, LLC	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 2009/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	NRG POWER MARKETING INC.	OS	Note 1			
2	NSP ENERGY MARKETING	OS	Note 1			
3	OHIO RETAIL	OS	Note 1			
4	OLD DOMINION ELEC.	OS	Note 1			
5	OPPD ENERGY MARKETING	OS	Note 1			
6	OTTER TAIL POWER COMPANY	OS	Note 1			
7	PARIBAS	OS	Note 1			
8	PENNSYLVANIA ELECTRIC COMPANY	OS	Note 1			
9	PENNSYLVANIA POWER COMPANY	OS	Note 1			
10	PEPCO SERVICES INC.	OS	Note 1			
11	PJM INTERCONNECTION	OS	Note 1			
12	POWEREX	OS	Note 1			
13	PP&L ENERGY PLUS CO.	OS	Note 1			
14	PPL ENERGY SUPPLY, LLC	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 2009/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	PRAIRIE POWER, INC.	OS	Note 1			
2	PRAIRIELAND ENERGY INCORPORATE	OS	Note 1			
3	PSEG ENERGY RESOURCES & TRADE	OS	Note 1			
4	RAINBOW ENERGY MARKETING	OS	Note 1			
5	REFCO INC.	OS	Note 1			
6	SEMPRA ENERGY SOLUTIONS, LLC	OS	Note 1			
7	SEMPRA ENERGY TRADING	OS	Note 1			
8	SHELL ENERGY N AMERICA (US) LP	OS	Note 1			
9	SOUTH CAROLINA ELECTRIC & GAS	OS	Note 1			
10	SOUTHEASTERN PUB SERV AUTH -VA	OS	Note 1			
11	SOUTHEN MARYLAND ELEC COOP INC	OS	Note 1			
12	SOUTHERN COMPANY	OS	Note 1			
13	SOUTHERN ILLINOIS POWER CO-OP	OS	Note 1			
14	STRATEGIC ENERGY LTD.	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 2009/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	TENASKA POWER SERVICES COMPANY	OS	Note 1			
2	THE BOROUGH OF PITCAIRN, PA	OS	Note 1			
3	THE ENERGY AUTHORITY	OS	Note 1			
4	THE POTOMAC EDISON COMPANY	OS	Note 1			
5	TOWN OF FRONT ROYAL	OS	Note 1			
6	TVA BULK POWER TRADING	OS	Note 1			
7	UBS AG, LONDON BRANCH	OS	Note 1			
8	UBS SECURITIES LLC	OS	Note 1			
9	UNION ELECTRIC COMPANY	OS	Note 1			
10	UNION POWER PARTNERS	OS	Note 1			
11	WABASH VALLEY POWER ASSN INC.	OS	Note 1			
12	WASHINGTON GAS ENERGY SERVICES	OS	Note 1			
13	WASHINGTON MILLS COMPANY, INC	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	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 2009/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	WISCONSIN POWER & LIGHT	OS	Note 1			
2	WOLVERINE POWER SUPPLY COOP	OS	Note 1			
3						
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.
477		34,261		34,261	1
6,441		414,423		414,423	2
2,142,856		84,078,185		84,078,185	3
33,650		1,684,519		1,684,519	4
137,628		4,793,887		4,793,887	5
37,829	1,571,724	948,397		2,520,121	6
193,392	756,448	8,267,807		9,024,255	7
193,696		10,747,122		10,747,122	8
394,694	8,121,782	7,053,664		15,175,446	9
45	1,551,723			1,551,723	10
779		117,208		117,208	11
20,452,478		935,562,440		935,562,440	12
41,623		69,053		69,053	13
-3,295		-203,123		-203,123	14
2,149,774	0	84,526,869	0	84,526,869	
26,202,795	12,001,677	1,197,682,165	0	1,209,683,842	
28,352,569	**12,001,677**	**1,282,209,034**	**0**	**1,294,210,711**	

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.
-18,476		-1,367,213		-1,367,213	1
10,133		732,444		732,444	2
170,056		10,183,209		10,183,209	3
-52		6,018		6,018	4
13,290		482,093		482,093	5
43,510		4,414,533		4,414,533	6
243,699		9,895,555		9,895,555	7
		78,699		78,699	8
		-33,213		-33,213	9
		237,459		237,459	10
1,395,413		69,915,865		69,915,865	11
-2,025		-97,447		-97,447	12
1,794		80,946		80,946	13
		62,931		62,931	14
2,149,774	0	84,526,869	0	84,526,869	
26,202,795	12,001,677	1,197,682,165	0	1,209,683,842	
28,352,569	**12,001,677**	**1,282,209,034**	**0**	**1,294,210,711**	

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.
		122,076		122,076	1
		-18		-18	2
		-3,877		-3,877	3
		12		12	4
		19,863		19,863	5
97,180		2,380,783		2,380,783	6
3,520		179,721		179,721	7
-505		359,629		359,629	8
4,771		835,337		835,337	9
64,013		4,226,691		4,226,691	10
3,336		133,803		133,803	11
3,837		144,489		144,489	12
		-25		-25	13
-336		-10,332		-10,332	14
2,149,774	0	84,526,869	0	84,526,869	
26,202,795	12,001,677	1,197,682,165	0	1,209,683,842	
28,352,569	**12,001,677**	**1,282,209,034**	**0**	**1,294,210,711**	

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.
168,570		6,189,323		6,189,323	1
-34,520		-2,590,663		-2,590,663	2
139,242		2,701,290		2,701,290	3
11		683		683	4
682		-5,638,906		-5,638,906	5
54,475		3,588,990		3,588,990	6
17,156		1,330,631		1,330,631	7
72		105,022		105,022	8
9,311		292,415		292,415	9
-2,616		-706,059		-706,059	10
3,182		-221,122		-221,122	11
496		-36,249		-36,249	12
		-10,060		-10,060	13
		-217		-217	14
2,149,774	0	84,526,869	0	84,526,869	
26,202,795	12,001,677	1,197,682,165	0	1,209,683,842	
28,352,569	**12,001,677**	**1,282,209,034**	**0**	**1,294,210,711**	

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.
-45,074		-1,593,948		-1,593,948	1
138,659		6,089,852		6,089,852	2
		-32,785		-32,785	3
-205		8,193		8,193	4
10,384		688,404		688,404	5
1,633		14,219		14,219	6
-132,632		-5,250,728		-5,250,728	7
2,693		118,041		118,041	8
163		383,078		383,078	9
		89,072		89,072	10
11,191		-487,012		-487,012	11
-421,638		-4,255,169		-4,255,169	12
713,175		45,154,894		45,154,894	13
		3,572		3,572	14
2,149,774	0	84,526,869	0	84,526,869	
26,202,795	12,001,677	1,197,682,165	0	1,209,683,842	
28,352,569	**12,001,677**	**1,282,209,034**	**0**	**1,294,210,711**	

SALES FOR RESALE (Account 447) (Continued)

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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)
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.
		2,435		2,435	1
20,134		1,248,095		1,248,095	2
		-205,673		-205,673	3
11,018		450,658		450,658	4
		185,096		185,096	5
151,388		10,459,180		10,459,180	6
62,872		4,379,942		4,379,942	7
60,522		2,437,122		2,437,122	8
567,804		18,233,267		18,233,267	9
83,041		2,068,284		2,068,284	10
-11,273		-397,160		-397,160	11
1,924		115,399		115,399	12
		-99,789		-99,789	13
9,440		554,214		554,214	14
2,149,774	0	84,526,869	0	84,526,869	
26,202,795	12,001,677	1,197,682,165	0	1,209,683,842	
28,352,569	**12,001,677**	**1,282,209,034**	**0**	**1,294,210,711**	

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)
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.
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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.
1,572		73,370		73,370	1
		-5		-5	2
		1,443,983		1,443,983	3
9,827		571,730		571,730	4
		-15,506		-15,506	5
255,027		11,346,856		11,346,856	6
9,591		-1,562,103		-1,562,103	7
		735		735	8
		-17,842		-17,842	9
-93,226		-2,632,422		-2,632,422	10
		-1,820,904		-1,820,904	11
45,714		2,353,889		2,353,889	12
		14,825		14,825	13
72		23,006		23,006	14
2,149,774	0	84,526,869	0	84,526,869	
26,202,795	12,001,677	1,197,682,165	0	1,209,683,842	
28,352,569	**12,001,677**	**1,282,209,034**	**0**	**1,294,210,711**	

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)
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.
-12,247		-761,036		-761,036	1
		-4,543		-4,543	2
		-12,480,408		-12,480,408	3
91,177		5,945,827		5,945,827	4
		-3,765		-3,765	5
-15,976		-474,414		-474,414	6
		13,403		13,403	7
-3,696		-161,153		-161,153	8
38,362		2,812,458		2,812,458	9
202,828		16,948,792		16,948,792	10
569,495		15,716,674		15,716,674	11
1,016		51,689		51,689	12
-11,193		-371,316		-371,316	13
		-423		-423	14
2,149,774	0	84,526,869	0	84,526,869	
26,202,795	12,001,677	1,197,682,165	0	1,209,683,842	
28,352,569	**12,001,677**	**1,282,209,034**	**0**	**1,294,210,711**	

SALES FOR RESALE (Account 447) (Continued)

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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)
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.
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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.
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.
34,516		2,449,071		2,449,071	1
14,781		542,644		542,644	2
-363,309		-22,764,229		-22,764,229	3
		1,978		1,978	4
		-12,792		-12,792	5
59,290		7,496,286		7,496,286	6
23,070		866,366		866,366	7
20,369		1,810,883		1,810,883	8
-1		-67		-67	9
		-37,547		-37,547	10
8,854		964,931		964,931	11
27,845		969,575		969,575	12
48,244		1,875,936		1,875,936	13
-4,384		25,836		25,836	14
2,149,774	0	84,526,869	0	84,526,869	
26,202,795	12,001,677	1,197,682,165	0	1,209,683,842	
28,352,569	**12,001,677**	**1,282,209,034**	**0**	**1,294,210,711**	

SALES FOR RESALE (Account 447) (Continued)

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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.
		5,620		5,620	1
739		46,707		46,707	2
7,134		265,854		265,854	3
54,750		3,541,228		3,541,228	4
1,126		-69,783		-69,783	5
3,009		59,694		59,694	6
63,254		2,453,187		2,453,187	7
		-6,836,793		-6,836,793	8
-161,440		-5,139,101		-5,139,101	9
-9,340		-283,904		-283,904	10
-102,479		-2,042,168		-2,042,168	11
137,668		8,936,370		8,936,370	12
		377,350		377,350	13
4,385		-7,604		-7,604	14
2,149,774	0	84,526,869	0	84,526,869	
26,202,795	12,001,677	1,197,682,165	0	1,209,683,842	
28,352,569	**12,001,677**	**1,282,209,034**	**0**	**1,294,210,711**	

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.
139,414		7,662,398		7,662,398	1
		126,006		126,006	2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
2,149,774	0	84,526,869	0	84,526,869	
26,202,795	12,001,677	1,197,682,165	0	1,209,683,842	
28,352,569	**12,001,677**	**1,282,209,034**	**0**	**1,294,210,711**	

FOOTNOTE DATA

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

AEP Affiliate.

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

NOTE 1: FERC Electric Tariff, Second Substitute Volume No. 5 (1st quarter 2009)
FERC Electric Tariff, First Revised Volume No. 5 (2nd, 3rd, and 4th quarter 2009)

Schedule Page: 310 Line No.: 8 Column: a

The termination of this contract is 05/31/2012

Schedule Page: 310 Line No.: 9 Column: a

The termination of this contract is December 31, 2010. However the contract could be cancelled or modified during the contract term by mutual agreement.

Schedule Page: 310 Line No.: 12 Column: a

Appalachian Power Company, Columbus Southern 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.: 13 Column: a

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

Schedule Page: 310.1 Line No.: 10 Column: c

Note 2: Third Revised Rate Schedule FERC No. 801

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 2009/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	18,378,371	18,282,434
5	(501) Fuel	899,340,627	1,091,473,652
6	(502) Steam Expenses	104,109,421	103,865,837
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	2,055,248	2,155,424
10	(506) Miscellaneous Steam Power Expenses	56,241,827	63,159,088
11	(507) Rents	66,774,232	64,095,393
12	(509) Allowances	5,569,548	13,648,138
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	1,152,469,274	1,356,679,966
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	12,639,034	13,195,777
16	(511) Maintenance of Structures	10,607,380	9,020,764
17	(512) Maintenance of Boiler Plant	98,446,429	102,622,792
18	(513) Maintenance of Electric Plant	17,373,020	21,233,069
19	(514) Maintenance of Miscellaneous Steam Plant	8,115,984	6,547,420
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	147,181,847	152,619,822
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	1,299,651,121	1,509,299,788
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	39,430	52,176
45	(536) Water for Power	26,882	25,375
46	(537) Hydraulic Expenses	11,065	8,802
47	(538) Electric Expenses	188	4,956
48	(539) Miscellaneous Hydraulic Power Generation Expenses	119,913	133,913
49	(540) Rents	50,000	50,000
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	247,478	275,222
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	397	
54	(542) Maintenance of Structures	21,558	27,771
55	(543) Maintenance of Reservoirs, Dams, and Waterways	-2,103	177
56	(544) Maintenance of Electric Plant	1,195,178	2,316,215
57	(545) Maintenance of Miscellaneous Hydraulic Plant	242,409	256,222
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	1,457,439	2,600,385
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	1,704,917	2,875,607

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 2009/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)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering		
63	(547) Fuel		
64	(548) Generation Expenses		
65	(549) Miscellaneous Other Power Generation Expenses		
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)		
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures		
71	(553) Maintenance of Generating and Electric Plant		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant		
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)		
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)		
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	319,505,447	403,265,330
77	(556) System Control and Load Dispatching	2,945,170	2,829,489
78	(557) Other Expenses	9,065,135	8,434,280
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	331,515,752	414,529,099
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	1,632,871,790	1,926,704,494
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	3,032,803	3,051,242
84	(561) Load Dispatching		
85	(561.1) Load Dispatch-Reliability	49,621	53,241
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	4,454,434	4,648,743
87	(561.3) Load Dispatch-Transmission Service and Scheduling	7,945	1,112
88	(561.4) Scheduling, System Control and Dispatch Services	3,399,831	3,862,973
89	(561.5) Reliability, Planning and Standards Development	255,851	103,182
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	638,327	670,559
93	(562) Station Expenses	1,025,369	1,072,691
94	(563) Overhead Lines Expenses	376,194	252,663
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	12,475,994	15,629,134
97	(566) Miscellaneous Transmission Expenses	5,420,614	16,933,867
98	(567) Rents	79,075	69,429
99	TOTAL Operation (Enter Total of lines 83 thru 98)	31,216,058	46,348,836
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	312,490	316,038
102	(569) Maintenance of Structures	110,183	106,241
103	(569.1) Maintenance of Computer Hardware	221,818	157,811
104	(569.2) Maintenance of Computer Software	1,138,947	1,029,122
105	(569.3) Maintenance of Communication Equipment	536,675	487,430
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	4,380,926	5,275,809
108	(571) Maintenance of Overhead Lines	7,914,045	7,638,077
109	(572) Maintenance of Underground Lines	-898	1,878
110	(573) Maintenance of Miscellaneous Transmission Plant	-4	14
111	TOTAL Maintenance (Total of lines 101 thru 110)	14,614,182	15,012,420
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	45,830,240	61,361,256

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 2009/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	3,628,655	3,356,418
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	3,628,655	3,356,418
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)	3,628,655	3,356,418
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	5,824,690	6,457,321
135	(581) Load Dispatching	7,903	13,424
136	(582) Station Expenses	1,285,540	1,206,629
137	(583) Overhead Line Expenses	1,169,432	446,660
138	(584) Underground Line Expenses	829,401	640,018
139	(585) Street Lighting and Signal System Expenses	127,566	140,192
140	(586) Meter Expenses	1,648,373	1,521,194
141	(587) Customer Installations Expenses	141,082	339,599
142	(588) Miscellaneous Expenses	11,563,646	16,942,586
143	(589) Rents	2,890,586	2,936,637
144	TOTAL Operation (Enter Total of lines 134 thru 143)	25,488,219	30,644,260
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	695,315	451,354
147	(591) Maintenance of Structures	161,720	149,284
148	(592) Maintenance of Station Equipment	3,160,491	3,640,858
149	(593) Maintenance of Overhead Lines	47,079,273	28,529,082
150	(594) Maintenance of Underground Lines	1,247,627	1,457,587
151	(595) Maintenance of Line Transformers	783,111	1,508,402
152	(596) Maintenance of Street Lighting and Signal Systems	331,776	227,280
153	(597) Maintenance of Meters	404,825	475,183
154	(598) Maintenance of Miscellaneous Distribution Plant	2,172,470	2,265,669
155	TOTAL Maintenance (Total of lines 146 thru 154)	56,036,608	38,704,699
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	81,524,827	69,348,959
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	1,388,685	1,482,796
160	(902) Meter Reading Expenses	4,923,442	5,540,885
161	(903) Customer Records and Collection Expenses	20,376,821	21,137,257
162	(904) Uncollectible Accounts	18,679,142	26,953,850
163	(905) Miscellaneous Customer Accounts Expenses	32,797	19,561
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	45,400,887	55,134,349

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 2009/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)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	1,751,547	1,529,194
168	(908) Customer Assistance Expenses	1,454,848	2,642,317
169	(909) Informational and Instructional Expenses	701,496	657,911
170	(910) Miscellaneous Customer Service and Informational Expenses	122	376
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	3,908,013	4,829,798
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	2,621	4,744
176	(913) Advertising Expenses	321	44,551
177	(916) Miscellaneous Sales Expenses	23,554	22,786
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	26,496	72,081
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	24,973,943	21,527,990
182	(921) Office Supplies and Expenses	852,476	3,922,213
183	(Less) (922) Administrative Expenses Transferred-Credit	2,821,096	2,569,476
184	(923) Outside Services Employed	21,531,837	29,426,111
185	(924) Property Insurance	3,622,786	3,339,677
186	(925) Injuries and Damages	8,594,719	5,445,059
187	(926) Employee Pensions and Benefits	39,643,136	25,630,628
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	243,481	284,922
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	1,538,158	727,015
192	(930.2) Miscellaneous General Expenses	1,287,756	1,383,524
193	(931) Rents	1,416,657	2,074,495
194	TOTAL Operation (Enter Total of lines 181 thru 193)	100,883,853	91,192,158
195	Maintenance		
196	(935) Maintenance of General Plant	5,149,337	4,494,143
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	106,033,190	95,686,301
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	1,919,224,098	2,216,493,656

FOOTNOTE DATA

Schedule Page: 320 Line No.: 84 Column: b

Any amounts for 561.0 for both current and prior period have been reclassified to 561.2.

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	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 2009/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	NATIONAL POWER COOPERATIVE INC	LF				
2	OHIO VALLEY ELECTRIC COMPANY	LF				
3	AEP SERVICE CORPORATION	OS	23			
4	AEP SERVICE CORPORATION	OS	20			
5	AEPES US GAS TRADING	OS				
6	ALLEGHENY ENERGY SUPPLY CO LLC	OS				
7	ALLETE, INC. DBA MINNESOTA PWR	OS				
8	AMEREN ENERGY MARKETING	OS				
9	ASSOCIATED ELECT COOPERATIVE	OS				
10	BARCLAYS BANK PLC	OS				
11	BP AMOCO	OS				
12	BUCKEYE RURAL ELECTRIC ADMIN	OS				
13	CALPINE POWER SERVICE COMPANY	OS				
14	CAROLINA POWER & LIGHT	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 2009/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)	Average Monthly CP Demand (f)
1	CITIGROUP ENERGY INC.	OS				
2	COMMONWEALTH EDISON CO	OS				
3	CONECTIV ENERGY SUPPLY INC.	OS				
4	CONOCO INC.	OS				
5	CONSTELLATION ENGY COMMODITIES	OS				
6	CREDIT SUISSE ENERGY	OS				
7	DOMINION EQUIPMENT INC	OS				
8	DP&L POWER SERVICES	OS				
9	DTE ENERGY TRADING INC.	OS				
10	DUKE ENERGY CAROLINAS, LLC	OS				
11	DUKE ENERGY INDIANA, INC.	OS				
12	DUKE POWER COMPANY	OS				
13	DYNEGY POWER MARKETING INC.	OS				
14	EDF TRADING NORTH AMERICA LLC	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 2009/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)	Average Monthly CP Demand (f)
1	EDISON MISSION MKTG & TRADING	OS				
2	ENDURE ENERGY, LLC	OS				
3	ENERGY AMERICA, LLC	OS				
4	ENTERGY POWER SERV	OS				
5	EXELON GENERATION - POWER TEAM	OS				
6	FIRSTENERGY TRADING SERVICES	OS				
7	FOWLER RIDGE II WIND FARM LLC	OS				
8	FPL ENERGY POWER MARKETINGINC	OS				
9	GEN SYS ENERGY	OS				
10	GREAT RIVER ENERGY	OS				
11	INDIANA MUNICIPAL POWER AGENCY	OS				
12	INDIANAPOLIS POWER & LIGHT CO	OS				
13	INTEGRYS ENERGY SERVICES, INC	OS				
14	JP MORGAN VENTURES ENERGY CORP	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 2009/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	KANSAS CITY POWER & LIGHT CO	OS				
2	LEVITAN AND ASSOCIATES INC.	OS				
3	LG&E UTILITIES POWER SALES	OS				
4	MADISON GAS AND ELECTRIC CO	OS				
5	MERRILL LYNCH COMMODITIES, INC	OS				
6	METROPOLITAN EDISON COMPANY	OS				
7	MICHIGAN PUBLIC POWER AGENCY	OS				
8	MIDWEST ISO	OS				
9	MINGO JUNCTION ENERGY CENTER	OS				
10	MORGAN STANLEY CAPT.	OS				
11	NIPSCO ENERGY MANAGEMENT	OS				
12	NO CAROLINA MUNI PWR AGENCY	OS				
13	NRG POWER MARKETING INC.	OS				
14	OHIO ECONOMIC DEVELOPMENT RIDER	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 2009/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	OLD DOMINION ELEC.	OS				
2	OPPD ENERGY MARKETING	OS				
3	OTTER TAIL POWER COMPANY	OS				
4	PENNSYLVANIA ELECTRIC COMPANY	OS				
5	PJM ENVIRONMENTAL INFO SYS INC	OS				
6	PJM INTERCONNECTION	OS				
7	PP&L ENERGY PLUS CO.	OS				
8	PSEG ENERGY RESOURCES & TRADE	OS				
9	RAINBOW ENERGY MARKETING	OS				
10	RRI ENERGY SERVICES, INC	OS				
11	SEMPRA ENERGY TRADING	OS				
12	SOUTH CAROLINA ELECTRIC & GAS	OS				
13	SOUTHEASTERN PUB SERV AUTH -VA	OS				
14	SOUTHEN MARYLAND ELEC COOP INC	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 2009/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)	Average Monthly CP Demand (f)
1	SOUTHERN COMPANY	OS				
2	STRATEGIC ENERGY LTD.	OS				
3	THE ENERGY AUTHORITY	OS				
4	TOWN OF FRONT ROYAL	OS				
5	TVA BULK POWER TRADING	OS				
6	UBS SECURITIES LLC	OS				
7	UNION ELECTRIC COMPANY	OS				
8	UNION POWER PARTNERS	OS				
9	WABASH VALLEY POWER ASSN INC.	OS				
10	WESTAR ENERGY INC.	OS				
11	WISCONSIN ELECTRIC POWER CO	OS				
12	WISCONSIN POWER & LIGHT	OS				
13	WISCONSIN PUBLIC SERVICE	OS				
14	WOLVERINE POWER SUPPLY COOP	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 2009/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)	Average Monthly CP Demand (f)
1	WPPI ENERGY	OS				
2	MISCELLANEOUS MWH ADJUSTMENTS					
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		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)	
5,377			68,059	-635,801		-567,742	1
2,497,234				102,079,765		102,079,765	2
1,957,423				72,360,363		72,360,363	3
10,126				-414,588		-414,588	4
				1,250,745		1,250,745	5
176				6,447		6,447	6
				216,830		216,830	7
1,322				51,732		51,732	8
3,094				104,045		104,045	9
				293,799		293,799	10
				-4,778		-4,778	11
				442,741		442,741	12
129				6,027		6,027	13
91				2,067		2,067	14
8,617,240			68,059	321,062,547	-1,625,159	319,505,447	

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)	POWER EXCHANGES MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	COST/SETTLEMENT OF POWER Energy Charges ($) (k)	COST/SETTLEMENT OF POWER Other Charges ($) (l)	COST/SETTLEMENT OF POWER Total (j+k+l) of Settlement ($) (m)	Line No.
				-513		-513	1
				7,167		7,167	2
				64,406		64,406	3
826				58,704		58,704	4
13,028				2,363,833		2,363,833	5
				-452		-452	6
8,352				375,247		375,247	7
672				20,089		20,089	8
2,568				72,050		72,050	9
				136		136	10
				67,603		67,603	11
243				14,248		14,248	12
				183,580		183,580	13
				-2,837		-2,837	14
8,617,240			68,059	321,062,547	-1,625,159	319,505,447	

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)	
12,421				364,501		364,501	1
				7,679		7,679	2
				346		346	3
2,024				75,164		75,164	4
683,031				26,378,479		26,378,479	5
				37,151		37,151	6
18,024				1,344,571		1,344,571	7
				-48,891		-48,891	8
				77,434		77,434	9
				34,132		34,132	10
				30,471		30,471	11
				1,604		1,604	12
10,608				570,080		570,080	13
				69,911		69,911	14
8,617,240			68,059	321,062,547	-1,625,159	319,505,447	

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)	
923				27,198		27,198	1
				1,891		1,891	2
3,084				115,131		115,131	3
				73,613		73,613	4
				4,481		4,481	5
19,456				835,070		835,070	6
				22,124		22,124	7
630,427				22,257,166		22,257,166	8
1,368				23,906		23,906	9
				148,762		148,762	10
				-21,899		-21,899	11
22				910		910	12
2,692				110,816		110,816	13
					-1,625,159	-1,625,159	14
8,617,240			68,059	321,062,547	-1,625,159	319,505,447	

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)	POWER EXCHANGES MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	COST/SETTLEMENT OF POWER Energy Charges ($) (k)	COST/SETTLEMENT OF POWER Other Charges ($) (l)	COST/SETTLEMENT OF POWER Total (j+k+l) of Settlement ($) (m)	Line No.
192				3,574		3,574	1
120				3,261		3,261	2
				121,733		121,733	3
15,584				673,917		673,917	4
				1,711		1,711	5
1,842,047				76,810,827		76,810,827	6
44,060				1,667,643		1,667,643	7
37,744				2,314,086		2,314,086	8
140				3,714		3,714	9
				9,055		9,055	10
1,553				31,020		31,020	11
221				12,451		12,451	12
36,840				1,996,756		1,996,756	13
160				8,064		8,064	14
8,617,240			68,059	321,062,547	-1,625,159	319,505,447	

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)	
373				14,430		14,430	1
176				11,864		11,864	2
523				24,917		24,917	3
				528,633		528,633	4
3,433				123,595		123,595	5
				4,174,466		4,174,466	6
528				111,826		111,826	7
1,305				41,148		41,148	8
				692,758		692,758	9
862				34,603		34,603	10
				46,686		46,686	11
				159,184		159,184	12
				48,672		48,672	13
				-174,368		-174,368	14
8,617,240			68,059	321,062,547	-1,625,159	319,505,447	

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)	
				41,865		41,865	1
746,638							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
8,617,240			68,059	321,062,547	-1,625,159	319,505,447	

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

The termination date of the contract is September 30, 2032.

Schedule Page: 326 Line No.: 2 Column: b

The termination date of the contract is the earlier of (1) March 13, 2026 or (2) the sale of or other disposition of all of the facilities of the Project Generating Stations or the permanent cessation of the operation of such facilities.

Schedule Page: 326 Line No.: 3 Column: a

An AEP Affiliate.

Schedule Page: 326 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 Integration Agreement for additional information.

Schedule Page: 326 Line No.: 5 Column: a

An AEP Affiliate.

Schedule Page: 326.3 Line No.: 14 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 Ormet under the Economic Development Rider (EDR). Charges to the (EDR) regulatory asset are offset to account 5550110.

Schedule Page: 326.6 Line No.: 2 Column: a

Ohio Power Company
Misc MWH Adjustments

Vendor	OPCO Demand	
Bookouts/Options	2,887	
Non-Gen Card 2&3	15,557	
MLR Purchases	(720,699)	
Spot Energy (PJM)	731,129	
5550003	(1,368)	
Pool Adjustment	726,787	*
PJM Non-ECR	(8,970)	
PJM Losses	238	
Fowler Wind Farm II	24	
Interruptible By-thru	1,053	
Total Misc MWH Adjustments	746,638	

* Pool Adjustment includes a prior year adjustment for June 2007 through July 2009 of 455,814 MWH.

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 2009/Q4

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

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	PJM Network Integ Trans Service	Various	Various	FNO
2	PJM Point to Point Trans Service	Various	Various	OLF
3	PJM Transmission Admin Revenues	Various	Various	OS
4	PJM Expansion Cost Recovery	Various	Various	OS
5	RTO Formation Cost Recovery	Various	Various	OS
6	PJM Trans Dist/Meter - NonAffiliated	Various	Various	OS
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				
	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 2009/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
						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
			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 2009/Q4

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 (I), 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.
12,069,241			12,069,241	1
2,754,233			2,754,233	2
		484,008	484,008	3
		363,875	363,875	4
		72,242	72,242	5
		828,803	828,803	6
				7
				8
				9
				10
				11
				12
				13
				14
				15
				16
				17
				18
				19
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				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
14,823,474	**0**	**1,748,928**	**16,572,402**	

FOOTNOTE DATA

Schedule Page: 328 Line No.: 1 Column: e

Effective October 1, 2004 the administration of the transmission tarriff was turned over to PJM. PJM does not provide any detail except for the total revenue by the major classes listed.

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 2009/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 2009/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		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Wheeling Power	LFP					1,359,166	1,359,166
2	PJM	OS					2,655,570	2,655,570
3	AEP Sys Trans Agreement	FNS					8,461,258	8,461,258
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL						12,475,994	12,475,994

FOOTNOTE DATA

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

Affiliated company.

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

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

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

The respondent, Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company are associated companies and are parties to the Transmission Agreement dated April 1, 1984, as amended. Pursuant to the terms of the Transmission Agreement, American Electric Power Service Corporation serves as agent and the parties pool their investment in high voltage transmission facilities (138kV and above) and share the cost of ownership in proportion to the respective member's load ratio. As such, there is no transfer of energy and some parties receive credits which are recorded in Account 565.

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 2009/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	336,739
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	16,790
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	131,042
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Affiliated InterCompany Billings (net)	440,074
7	Associated Business Development	288,239
8	Chambers of Commerce	27,996
9	Write-off unclaimed funds (business to business)	-10,452
10	Relocation Costs	48,133
11	Various Items < $5,000	9,195
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
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31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46	TOTAL	1,287,756

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 2009/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			17,662,788		17,662,788
2	Steam Production Plant	215,251,415	3,514,307	1,826,620		220,592,342
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	2,998,687	169			2,998,856
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant					
7	Transmission Plant	25,505,773				25,505,773
8	Distribution Plant	59,661,524				59,661,524
9	Regional Transmission and Market Operation					
10	General Plant	3,964,685		988,278		4,952,963
11	Common Plant-Electric					
12	TOTAL	307,382,084	3,514,476	20,477,686		331,374,246

B. Basis for Amortization Charges

Line 1, Column D represents amortization of capitalized software development costs over a 5 year life.

Lines 2 & 10, Column D represent amortization of leasehold improvements to equipment and structures over the life of the lease.

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 2009/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	STEAM GENERATION						
13	311	342,055			2.91		
14	312	4,371,094			3.24		
15	314	565,959			3.70		
16	315	173,943			3.65		
17	316	59,636			3.45		
18	Total Steam Generation	5,512,687					
19							
20	HYDRO GENERATION						
21	331	49,964			2.78		
22	332	6,305			2.60		
23	333	42,418			2.56		
24	334	10,009			2.57		
25	335	4,352			2.36		
26	Total Hydro Generation	113,048					
27							
28	TRANSMISSION						
29	352	35,722	55.00		1.91	R4	
30	353	616,965	45.00	5.00	2.33	R0.5	
31	354	139,197			1.67		
32	355	119,680			4.14		
33	356	187,535			1.81		
34	357	366	50.00		2.00	R2	
35	358	901	50.00		2.00	R2	
36	Total Transmission	1,100,366					
37							
38	DISTRIBUTION						
39	361	8,070	55.00	5.00	1.91	R2	
40	362	234,355	35.00		2.86	L0	
41	363	5,062			6.67		
42	364	316,603	32.00	55.00	4.84	L0	
43	365	277,176	30.00	20.00	4.00	S1.5	
44	366	51,094	50.00		2.00	R3	
45	367	90,118	30.00		3.33	L3	
46	368	312,751	33.00	20.00	3.64	L0	
47	369	132,021	33.00	50.00	4.55	R0.5	
48	370	70,431	32.00	25.00	3.91	R0.5	
49	371	21,842	12.00	20.00	10.00	L0	
50	372	1	30.00		3.33	R1	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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	373	20,880	20.00	15.00	5.75	L0	
13	Total Distribution	1,540,404					
14							
15	GENERAL PLANT						
16	390	58,001	45.00	15.00	2.56	R2	
17	391	3,191	30.00	-5.00	3.17	L0.5	
18	392	32	50.00	-5.00	1.90	R1	
19	393	270	32.00		3.13	R5	
20	394	15,319	25.00	-5.00	3.80	R2.5	
21	395	570	28.00	-2.00	3.50	S4	
22	396	631	26.00	-10.00	3.46	L4	
23	397	32,853	35.00		2.86	L0	
24	398	1,716	25.00		4.00	R1	
25	TOTAL GENERAL	112,583					
26							
27	DEPRECIABLE SUM	8,379,088					
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44							
45							
46							
47							
48							
49							
50							

FOOTNOTE DATA

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: 336.1 Line No.: 27 Column: b

Assigned Schedule page within FERC Software is incorrect
Correction: Schedule Page: 337.1 Line No.: 27 Column: b
The depreciable plant base is the November 30, 2009 total company depreciable plant.

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 2009/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 hearings				
2	and review process of long-term forcasts.	159,392		159,392	
3					
4	Racine Hydro Project #2570				
5	Proportion of Cost of Administering the				
6	Federal Water Power Act	87,243		87,243	
7					
8	Miscellaneous		-3,154	-3,154	
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	246,635	-3,154	243,481	

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 2009/Q4

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO			Deferred to Account 182.3	Contra Account	Amount	Deferred in Account 182.3 End of Year	Line No.
Department (f)	Account No. (g)	Amount (h)	(i)	(j)	(k)	(l)	
							1
Electric	928	159,392					2
							3
							4
							5
Electric	928	87,243					6
							7
Electric	928	-3,154					8
							9
							10
							11
							12
							13
							14
							15
							16
							17
							18
							19
							20
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							40
							41
							42
							43
							44
							45
		243,481					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 2009/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) Steam	Adv Generation Asset Program Management
3		Coal Utilization Research
4		5 items under $50,000
5		
6		
7	(e) Unconventional Generation	Distributed Energy Resources Program Management
8		3 items under $50,000
9		
10		
11	A.(2) Transmission	6 items under $50,000
12		
13		
14		
15		
16	A.(2) Transmission	
17	(a) Overhead	1 items under $50,000
18		
19	A.(3) Distribution	4 items under $50,000
20		
21		
22		
23		
24	A.(4) Regional Transmission and Market Op	1 items under $50,000
25		
26	A.(5) Environment	Industrial Advisory Committee - Southern Co.
27		7 items under $50,000
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		

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 2009/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.(6) Other	Corporate Technology Progam Management
2		Grid of the Future Test Bed
3		8 items under $50,000
4		
5		
6		
7		
8		
9		
10	A (7) TOTAL COST INCURRED INTERNALLY	
11		
12	ELECTRIC UTILITY RESEARCH, DEVELOPMENT &	
13	DEMONSTRATION PERFORMED EXTERNALLY	
14		
15	B. (1) Electric Power Research Institute	EPRI Annual Portfolio
16		EPRI Demo IGCC with CO2 Capture & Storage
17		EPRI Demo Ion Transport Membrane Oxygen
18		EPRI Demo Post Combustion CO2 Capture & Storage
19		EPRI Environmental Controls
20		EPRI Environmental Science
21		Ohio River Ecological Research Program
22		56 items under $50,000
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		

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 2009/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	B. (4) Research Support to Others	8 items under $50,000
2		
3		
4		
5		
6		
7		
8		
9		
10		
11	B(5) TOTAL COSTS INCURRED EXTERNALLY	
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
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36		
37		
38		

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 2009/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

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

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation (g)	Line No.
		Account (e)	Amount (f)		
					1
56,047		506	56,047		2
51,500		506	51,500		3
68,768		506	68,768		4
					5
					6
71,411		588	71,411		7
-33,501		Various	-33,501		8
					9
					10
39,470		566	39,470		11
					12
					13
					14
					15
					16
2,691		566	2,691		17
					18
907		Various	907		19
					20
					21
					22
					23
2,082		588	2,082		24
					25
305,697		506	305,697		26
82,220		506	82,220		27
					28
					29
					30
					31
					32
					33
					34
					35
					36
					37
					38

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 2009/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

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

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation (g)	Line No.
		Account (e)	Amount (f)		
89,688		588	89,688		1
79,101		588	79,101		2
50,935		Various	50,935		3
					4
					5
					6
					7
					8
					9
867,016			867,016		10
					11
					12
					13
					14
380,685		Various	380,685		15
305,697		506	305,697		16
102,498		506	102,498		17
255,837		506	255,837		18
294,258		506	294,258		19
1,054,054		506	1,054,054		20
63,104		506	63,104		21
523,774		Various	523,774		22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
					33
					34
					35
					36
					37
					38

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 2009/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

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

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation (g)	Line No.
		Account (e)	Amount (f)		
119,589		Various	119,589		1
					2
					3
					4
					5
					6
					7
					8
					9
					10
3,099,496			3,099,496		11
					12
					13
					14
					15
					16
					17
					18
					19
					20
					21
					22
					23
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					37
					38

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 2009/Q4

DISTRIBUTION OF SALARIES AND WAGES

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

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	35,524,848		
4	Transmission	2,081,267		
5	Regional Market			
6	Distribution	6,647,939		
7	Customer Accounts	5,978,707		
8	Customer Service and Informational	1,505,763		
9	Sales			
10	Administrative and General	6,307,609		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	58,046,133		
12	Maintenance			
13	Production	44,224,575		
14	Transmission	3,924,878		
15	Regional Market			
16	Distribution	14,508,096		
17	Administrative and General	1,569,211		
18	TOTAL Maintenance (Total of lines 13 thru 17)	64,226,760		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	79,749,423		
21	Transmission (Enter Total of lines 4 and 14)	6,006,145		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	21,156,035		
24	Customer Accounts (Transcribe from line 7)	5,978,707		
25	Customer Service and Informational (Transcribe from line 8)	1,505,763		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	7,876,820		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	122,272,893	6,500,156	128,773,049
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	122,272,893	6,500,156	128,773,049
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	32,314,875	1,717,893	34,032,768
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	32,314,875	1,717,893	34,032,768
72	Plant Removal (By Utility Departments)			
73	Electric Plant	6,783,642	360,626	7,144,268
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	6,783,642	360,626	7,144,268
77	Other Accounts (Specify, provide details in footnote):			
78				
79	122 - Depr and Amortization	8,994		8,994
80	152 - Fuel Stock Undistributed	9,454,401		9,454,401
81	163 - Stores Expense Undistributed	5,613,741	-5,613,741	
82	184 - Clearing Accounts	2,964,934	-2,964,934	
83	185 - ODD Temporary Facilities	88,652		88,652
84	186 - Misc Deferred Debits	782,464		782,464
85	188 - Research & Development	813		813
86	401 - Operation Exp - Nonassociated	20		20
87	402 - Maintenance Expense	105,970		105,970
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	19,019,989	-8,578,675	10,441,314
96	TOTAL SALARIES AND WAGES	180,391,399		180,391,399

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 2009/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	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 2009/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)				13,660,394
3	Net Sales (Account 447)				(17,144,528)
4	Transmission Rights				(2,748,739)
5	Ancillary Services				1,616,777
6	Other Items (list separately)				
7	Congestion				3,643,888
8	Operating Revenues				905,018
9	Transmission Purchase Expense				(1,146)
10	Transmission Losses				6,691,211
11	Meter Corrections				26,327
12	Inadvertent				(79,278)
13	Miscellaneous				(2,360,686)
14					
15					
16					
17					
18					
19					
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21					
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39					
40					
41					
42					
43					
44					
45					
46	TOTAL				4,209,238

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 2009/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		N/A		757,885	0.32/MWH	242,979
2	Reactive Supply and Voltage		N/A				
3	Regulation and Frequency Response		N/A				
4	Energy Imbalance		N/A				
5	Operating Reserve - Spinning		N/A				
6	Operating Reserve - Supplement		N/A				
7	Other		N/A				
8	Total (Lines 1 thru 7)				757,885		242,979

FOOTNOTE DATA

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

Represents Company's MLR share of AEP Systems revenues, Column G, divided by Column F.

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

The unit of measure for all ancillary services except energy imbalance.

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

Represents Company's member load ratio (MLR) of AEP System's ancillary 1 service revenues for grandfathered agreements.

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 2009/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									

FOOTNOTE DATA

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	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 2009/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 2009/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)	24,936,379
3	Steam	47,483,755	23	Requirements Sales for Resale (See instruction 4, page 311.)	2,149,774
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	26,202,795
5	Hydro-Conventional	216,867	25	Energy Furnished Without Charge	1,003
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
7	Other		27	Total Energy Losses	3,027,911
8	Less Energy for Pumping		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	56,317,862
9	Net Generation (Enter Total of lines 3 through 8)	47,700,622			
10	Purchases	8,617,240			
11	Power Exchanges:				
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)	56,317,862			

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 2009/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 (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	Day of Month (e)	Hour (f)
29	January	5,277,982	2,265,745	4,972	20	1000
30	February	4,427,869	1,876,298	4,866	5	0800
31	March	4,614,793	2,048,119	4,670	2	2000
32	April	4,129,465	1,802,007	4,156	7	0800
33	May	3,106,753	850,728	3,957	28	1300
34	June	4,401,770	2,084,936	4,682	25	1500
35	July	4,927,895	2,571,096	4,419	16	1600
36	August	5,064,197	2,537,171	4,888	10	1400
37	September	4,703,824	2,417,940	4,185	15	1400
38	October	4,790,488	2,559,478	3,694	19	0700
39	November	4,959,137	2,702,530	3,848	6	1000
40	December	5,913,689	3,310,825	4,510	10	2000
41	TOTAL	56,317,862	27,026,873			

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 2009/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)	876			2902		
7	Plant Hours Connected to Load	5376			7279		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	867			2900		
10	When Limited by Condenser Water	857			2885		
11	Average Number of Employees	109			370		
12	Net Generation, Exclusive of Plant Use - KWh	3568240000			13069422000		
13	Cost of Plant: Land and Land Rights	652289			5303691		
14	Structures and Improvements	36033988			112204277		
15	Equipment Costs	888281375			2290727186		
16	Asset Retirement Costs	15060362			44085513		
17	Total Cost	940028014			2452320667		
18	Cost per KW of Installed Capacity (line 17/5) Including	1084.2307			836.1134		
19	Production Expenses: Oper, Supv, & Engr	3264587			10731985		
20	Fuel	100090313			362332437		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	7728710			21326887		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	60574			237546		
26	Misc Steam (or Nuclear) Power Expenses	1676484			6100563		
27	Rents	108903			90147		
28	Allowances	84584			1343810		
29	Maintenance Supervision and Engineering	1494947			5528331		
30	Maintenance of Structures	1319156			4597121		
31	Maintenance of Boiler (or reactor) Plant	10381220			42086131		
32	Maintenance of Electric Plant	1603590			7036582		
33	Maintenance of Misc Steam (or Nuclear) Plant	856773			2834044		
34	Total Production Expenses	128669841			464245584		
35	Expenses per Net KWh	0.0361			0.0355		
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	1480175	35326	0	5319180	99497	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	12150	137936	0	12061	137956	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	63.211	82.039	0.000	63.525	79.780	0.000
41	Average Cost of Fuel per Unit Burned	63.331	88.272	0.000	63.814	89.197	0.000
42	Average Cost of Fuel Burned per Million BTU	2.606	15.237	0.000	2.645	15.394	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.026	0.000	0.000	0.026	0.000	0.000
44	Average BTU per KWh Net Generation	10142.000	0.000	0.000	9861.000	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 2009/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: *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)	1114			1837		
7	Plant Hours Connected to Load	6549			7766		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	595			1820		
10	When Limited by Condenser Water	585			1800		
11	Average Number of Employees	333			333		
12	Net Generation, Exclusive of Plant Use - KWh	4652138000			10784462000		
13	Cost of Plant: Land and Land Rights	417437			605833		
14	Structures and Improvements	40878901			94833323		
15	Equipment Costs	656024104			1221479137		
16	Asset Retirement Costs	6269756			6269756		
17	Total Cost	703590198			1323188049		
18	Cost per KW of Installed Capacity (line 17/5) Including	1144.0491			703.4493		
19	Production Expenses: Oper, Supv, & Engr	1506558			4704730		
20	Fuel	114364923			270828359		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	10588742			21321734		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	643366			1979953		
26	Misc Steam (or Nuclear) Power Expenses	2569729			7380453		
27	Rents	0			0		
28	Allowances	92948			0		
29	Maintenance Supervision and Engineering	1072091			2662679		
30	Maintenance of Structures	1148851			2712018		
31	Maintenance of Boiler (or reactor) Plant	13004621			39159573		
32	Maintenance of Electric Plant	1790268			4115515		
33	Maintenance of Misc Steam (or Nuclear) Plant	757146			1815839		
34	Total Production Expenses	147539243			356680853		
35	Expenses per Net KWh	0.0317			0.0331		
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	1818824	25229	0	4457782	55561	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	12131	138488	0	11835	138418	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	59.056	78.836	0.000	58.415	75.894	0.000
41	Average Cost of Fuel per Unit Burned	58.626	83.513	0.000	59.665	99.223	0.000
42	Average Cost of Fuel Burned per Million BTU	2.416	14.358	0.000	2.521	17.068	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.023	0.000	0.000	0.025	0.000	0.000
44	Average BTU per KWh Net Generation	9567.000	0.000	0.000	9820.000	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 2009/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	0.0000			0.0000		
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

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 2009/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
801.00			1106.00			2600.00			5
777			1081			2667			6
5424			6036			7961			7
0			0			0			8
750			1050			2640			9
730			1020			2630			10
139			193			294			11
1682181000			2495273000			19160246000			12
101828			172464			2934019			13
26402295			39369242			107815740			14
342527576			463537940			1791991539			15
5709212			8008578			-2346998			16
374740911			511088224			1900394300			17
467.8413			462.1051			730.9209			18
2698047			3981802			4034804			19
65799709			98016860			431658144			20
0			0			0			21
2253845			3579276			60838914			22
0			0			0			23
0			0			0			24
977139			1451253			92318			25
2498204			3725541			18825904			26
168253			199289			66497077			27
409684			565390			952910			28
470438			733444			1351904			29
1319812			2157556			2589637			30
6575103			11850192			32850580			31
1355919			3541502			4288965			32
945309			1468430			1805581			33
85471462			131270535			625786738			34
0.0508			0.0526			0.0327			35
Coal	Oil		Coal	Oil		Coal	Oil		36
Tons	Barrels		Tons	Barrels		Tons	Barrels		37
708430	14714	0	1061713	21648	0	8114407	31045	0	38
12065	137161	0	12074	137119	0	11672	138787	0	39
91.705	80.292	0.000	90.834	81.552	0.000	50.595	75.148	0.000	40
87.081	87.525	0.000	86.652	87.571	0.000	50.467	80.691	0.000	41
3.609	15.193	0.000	3.588	15.206	0.000	2.162	13.843	0.000	42
0.037	0.000	0.000	0.037	0.000	0.000	0.021	0.000	0.000	43
10212.000	0.000	0.000	10323.000	0.000	0.000	9895.000	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 2009/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: *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
1425			1565			633			6
7273			7380			5850			7
0			0			0			8
1440			1560			630			9
1390			1560			600			10
202			227			135			11
7299585000			9389850000			1731515000			12
973860			1122477			165993			13
56368633			76786169			32475786			14
596028358			1615879447			281471222			15
2882300			1193671			3649567			16
656253151			1694981764			317762568			17
428.9236			1037.9558			445.6698			18
2459020			3194400			1220954			19
185016615			221833729			75762758			20
0			0			0			21
9042043			12975384			681782			22
0			0			0			23
0			0			0			24
243968			15050			22833			25
6597149			7831356			16243002			26
0			0			0			27
3310699			130664			588057			28
370424			3261200			4618030			29
2568519			1176116			485289			30
14153919			15150447			6330539			31
3169762			3858523			1305993			32
2280543			1043946			426687			33
229212661			270470815			107685924			34
0.0314			0.0288			0.0622			35
Coal	Oil		Coal	Oil		Coal	Oil		36
Tons	Barrels		Tons	Barrels		Tons	Barrels		37
2860742	35974	0	3633596	27964	0	804339	9724	0	38
12620	138610	0	12483	139298	0	11240	138668	0	39
62.802	68.261	0.000	61.067	83.134	0.000	82.868	78.272	0.000	40
62.598	75.715	0.000	58.902	104.303	0.000	89.736	79.188	0.000	41
2.480	13.006	0.000	2.359	17.828	0.000	3.992	13.597	0.000	42
0.025	0.000	0.000	0.023	0.000	0.000	0.042	0.000	0.000	43
9920.000	0.000	0.000	9679.000	0.000	0.000	10470.000	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 2009/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: (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
0.0000	0.0000	0.0000	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

FOOTNOTE DATA

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

Plant Name: Amos - This plant is owned jointly by Respondent and Appalachian Power Company, also a subsidiariy 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

Deferred fuel expenses and Coal Procurement Net Sales totalling ($297,570,318) and $2,384,754, respectively, 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.: 15 Column: e

Included in Mitchell Plant's equipment costs is $13,193,208 investment, paid for 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.

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 2009/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)	46	0
7	Plant Hours Connect to Load	8,529	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	216,867,000	0
13	Cost of Plant		
14	Land and Land Rights	3,992	0
15	Structures and Improvements	49,964,061	0
16	Reservoirs, Dams, and Waterways	6,304,465	0
17	Equipment Costs	56,779,300	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	4,136	0
20	TOTAL cost (Total of 14 thru 19)	113,055,954	0
21	Cost per KW of Installed Capacity (line 20 / 5)	2,380.1253	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	39,430	0
24	Water for Power	26,882	0
25	Hydraulic Expenses	11,065	0
26	Electric Expenses	188	0
27	Misc Hydraulic Power Generation Expenses	119,913	0
28	Rents	50,000	0
29	Maintenance Supervision and Engineering	397	0
30	Maintenance of Structures	21,558	0
31	Maintenance of Reservoirs, Dams, and Waterways	-2,103	0
32	Maintenance of Electric Plant	1,195,178	0
33	Maintenance of Misc Hydraulic Plant	242,409	0
34	Total Production Expenses (total 23 thru 33)	1,704,917	0
35	Expenses per net KWh	0.0079	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 2009/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 2009/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	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 2009/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
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
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			28
			29
			30
			31
			32
			33
			34
			35
			36
			37
			38

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 2009/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						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
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20						
21						
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26						
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43						
44						
45						
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 2009/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		Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
		Fuel (i)	Maintenance (j)			
						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
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						35
						36
						37
						38
						39
						40
						41
						42
						43
						44
						45
						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 2009/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	0168 BAKER	DON MARQUIS	765.00	765.00	AT	26.41		1
2	0168 BAKER	DON MARQUIS	765.00	765.00	ST	10.32		1
3	0171 KAMMER	DUMONT	765.00	765.00	AT	100.19		1
4	0171 KAMMER	DUMONT	765.00	765.00	ST	126.14		1
5	0194 AMOS	NORTH PROCTORVILLE	765.00	765.00	ST	5.30		1
6	0195 GAVIN	MARYSVILLE	765.00	765.00	ST	124.40		1
7	0232 AMOS	GAVIN	765.00	765.00	ST	0.49		1
8	0233 GAVIN	KAMMER	765.00	765.00	ST	2.62		1
9	0263 KAMMER	SOUTH CANTON	765.00	765.00	AT	0.24		1
10	0263 KAMMER	SOUTH CANTON	765.00	765.00	ST	78.44		1
11	0269 NORTH	HANGING ROCK	765.00	765.00	ST	25.99		1
12	0270 HANGING ROCK	JEFFERSON	765.00	765.00	ST	6.14		1
13	0047 SPORN	MUSKINGUM	345.00	345.00	ST	46.52		1
14	0048 MUSKINGUM	CENTRAL	345.00	345.00	ST	28.10		1
15	0048 MUSKINGUM	CENTRAL	345.00	345.00	ST	53.94		2
16	0052 CENTRAL	EAST LIMA	345.00	345.00	ST	2.68		1
17	0052 CENTRAL	EAST LIMA	345.00	345.00	ST	71.36		2
18	0070 EAST LIMA	SORENSON	345.00	345.00	ST	42.99		1
19	0079 MUSKINGUM	TIDD	345.00	345.00	ST	83.57		2
20	0088 KAMMER EXT. NO. 1		345.00	345.00	ST	0.20		1
21	0088 KAMMER EXT. NO. 1		345.00	345.00	ST	0.38		1
22	0104 TIDD	CANTON CENTRAL	345.00	345.00	AT	37.29		1
23	0104 TIDD	CANTON CENTRAL	345.00	345.00	ST	14.21		1
24	0106 CANTON CENTRAL	JUNIPER	345.00	345.00	AT	4.06		1
25	0106 CANTON	JUNIPER	345.00	345.00	ST	1.36		1
26	0106 CANTON	JUNIPER	345.00	345.00	ST	0.55		2
27	0119 MUSKINGUM	OHIO CENTRAL	345.00	345.00	AT	30.75		1
28	0119 MUSKINGUM	OHIO CENTRAL	345.00	345.00	ST	12.51		1
29	0142 KAMMER EXT. NO. 2		345.00	345.00	ST	0.15		1
30	0142 KAMMER EXT. NO. 2		345.00	345.00	ST	0.30		1
31	0161 OHIO CENTRAL	FOSTORIA CENTRAL	345.00	345.00	AT	100.53		1
32	0161 OHIO CENTRAL	FOSTORIA CENTRAL	345.00	345.00	ST	5.99		1
33	0162 FOSTORIA CENTRAL	EAST LIMA	345.00	345.00	AT	34.47		1
34	0162 FOSTORIA CENTRAL	EAST LIMA	345.00	345.00	ST	5.35		1
35	0163 FOSTORIA CENTRAL	PEMBERVILLE	345.00	345.00	ST	19.29		2
36					TOTAL	5,513.56		403

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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	0166 SOUTH CANTON	SAMMIS	345.00	345.00	ST	0.74		1
2	0167 SOUTH CANTON	STAR	345.00	345.00	ST	0.69		1
3	0172 SOUTHWEST LIMA		345.00	345.00	ST	14.68		2
4	0173 SOUTHWEST LIMA	MIAMI	345.00	345.00	AT	18.04		1
5	0173 SOUTHWEST LIMA	MIAMI	345.00	345.00	ST	0.97		1
6	0208 TIDD	COLIER	345.00	345.00	ST	0.31		2
7	0248 MARYSVILLE EXT NO		345.00	345.00	ST	4.22		2
8	0249 MARYSVILLE EXT NO		345.00	345.00	ST	4.84		2
9	0279 SOUTH CANTON	CANTON CENTRAL	345.00	345.00	ST	8.16		2
10	0365 WATERFORD		345.00	345.00				
11	0366 BEVERLY EXTENSION		345.00	345.00	ST	0.10		
12	0001 LIMA	FT WAYNE	138.00	138.00	WP	0.10		2
13	0001 LIMA	FT WAYNE	138.00	138.00	ST	43.58		2
14	0004 HOWARD	ASHLAND	138.00	138.00	ST	6.15		1
15	0004 HOWARD	ASHLAND	138.00	138.00	ST	1.84		2
16	0005 WINDSOR	CANTON	138.00	138.00	ST	54.39		1
17	0005 WINDSOR	CANTON	138.00	138.00	WP	0.08		1
18	0006 WINDSOR	CANTON (WV)	138.00	138.00	ST	0.32		1
19	0007 PHILO	HOWARD	138.00	138.00	WP	0.05		2
20	0007 PHILO	HOWARD	138.00	138.00	ST	80.73		2
21	0010 FOSTORIA	PEMBERVILLE	138.00	138.00	ST	18.49		2
22	0010 FOSTORIA	PEMBERVILLE	138.00	138.00	ST	0.06		1
23	0010 FOSTORIA	PEMBERVILLE	138.00	138.00	WP			1
24	0011 PHILO	RUTLAND	138.00	138.00	ST	65.70		2
25	0016 SOUTH POINT	TURNER	138.00	138.00	ST	0.48		2
26	0018 PHILO	TORREY	138.00	138.00	ST	70.73		1
27	0019 CROOKSVILLE	WEST LANCASTER	138.00	138.00	ST	30.70		2
28	0020 PHILO	CANTON	138.00	138.00	ST	74.04		1
29	0025 TIDD	WAGENHALS	138.00	138.00	ST	53.45		1
30	0028 PORTSMOUTH	TRENTON NO. 2	138.00	138.00	WP	67.70		1
31	0028 PORTSMOUTH	TRENTON NO. 2	138.00	138.00	ST	0.24		1
32	0028 PORTSMOUTH	TRENTON NO. 2	138.00	138.00	ST	0.45		2
33	0032 TRENTON	MUNCIE	138.00	138.00	ST	23.92		1
34	0033 RUTLAND	SPORN	138.00	138.00	ST	4.81		2
35	0034 SPORN	SOUTH POINT	138.00	138.00	ST	9.22		1
36					TOTAL	5,513.56		403

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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	0034 SPORN	SOUTH POINT	138.00	138.00	ST	40.41		2
2	0036 SPORN	PORTSMOUTH	138.00	138.00	ST	0.05		1
3	0036 SPORN	PORTSMOUTH	138.00	138.00	ST	48.76		2
4	0037 HILLSBORO	MAYSVILLE	138.00	138.00	WP	33.55		1
5	0038 CROOKSVILLE	NORTH NEWARK	138.00	138.00	WP	30.67		1
6	0038 CROOKSVILLE	NORTH NEWARK	138.00	138.00	ST	0.58		2
7	0039 WEST LANCASTER	SOUTH BALTIMORE	138.00	138.00	WP	9.82		1
8	0041 NORTH NEWARK	WEST MT. VERNON	138.00	138.00	WP	20.28		1
9	0041 NORTH NEWARK	WEST MT. VERNON	138.00	138.00	ST	1.48		2
10	0042 SOUTH BALTIMORE	NORTH NEWARK	138.00	138.00	WP	21.04		1
11	0042 SOUTH BALTIMORE	NORTH NEWARK	138.00	138.00	ST	0.05		1
12	0042 SOUTH BALTIMORE	NORTH NEWARK	138.00	138.00	ST	0.08		2
13	0043 BELLEFONTE EXT.		138.00	138.00	ST	2.80		2
14	0044 SUMMERFIELD	NATRIUM	138.00	138.00	ST	27.07		2
15	0045 PHILO	MUSKINGUM	138.00	138.00	ST	23.16		2
16	0046 MUSKINGUM	SUMMERFIELD	138.00	138.00	ST	25.31		2
17	0049 FOSTORIA	EAST LIMA	138.00	138.00	WP	0.06		1
18	0049 FOSTORIA	EAST LIMA	138.00	138.00	ST	40.77		2
19	0050 EAST LIMA	LIMA	138.00	138.00	ST	4.43		2
20	0055 TORREY	WOOSTER	138.00	138.00	WP	28.69		1
21	0056 WEST MT. VERNON	SOUTH KENTON	138.00	138.00	WP	59.06		1
22	0057 SOUTH KENTON	STERLING	138.00	138.00	CP			1
23	0057 SOUTH KENTON	STERLING	138.00	138.00	WP	28.40		1
24	0058 SOUTH POINT	PORTSMOUTH	138.00	138.00	ST	0.04		1
25	0058 SOUTH POINT	PORTSMOUTH	138.00	138.00	ST	34.57		2
26	0059 PHILO	CROOKSVILLE	138.00	138.00	ST	15.37		2
27	0060 LIMA	STERLING	138.00	138.00	WP	5.96		1
28	0061 EAST LIMA	WEST LIMA	138.00	138.00	WP	0.15		2
29	0061 EAST LIMA	WEST LIMA	138.00	138.00	ST	11.19		2
30	0061 EAST LIMA	WEST LIMA	138.00	138.00	ST	1.05		3
31	0063 TORREY	MASSILLON	138.00	138.00	ST	0.29		2
32	0066 WAGENHALS	WEST CANTON	138.00	138.00	ST	9.16		1
33	0066 WAGENHALS	WEST CANTON	138.00	138.00	ST	0.85		2
34	0067 TORREY	AKRON	138.00	138.00	ST	0.28		1
35	0069 TIDD	SOUTH CADIZ	138.00	138.00	WP	16.59		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	0071 AKRON	CANTON	138.00	138.00	ST	3.75		1
2	0072 TIDD	WEIRTON NO. 2	138.00	138.00	WP	6.21		1
3	0072 TIDD	WEIRTON NO. 2	138.00	138.00	ST	0.05		1
4	0073 WEIRTON	SOUTH TORONTO	69.00	138.00	ST	0.48		2
5	0073 WEIRTON	SOUTH TORONTO	138.00	138.00	ST	0.14		1
6	0075 SPORN	KAISER NO. 1	138.00	138.00	ST	4.25		2
7	0076 LUCASVILLE	SARGENTS	138.00	138.00	WP	11.88		1
8	0078 TIDD	WINDSOR JCT.	138.00	138.00	ST	3.77		1
9	0080 NEWCOMERSTOWN	SOUTH COSHOCTON	138.00	138.00	WP	14.33		1
10	0081 FORD MOTOR EXT		138.00	138.00	ST	0.25		2
11	0086 SPORN	KAISER NO. 2	138.00	138.00	ST	5.67		2
12	0087 WINDSOR JUNCTION	TILTONVILLE	138.00	138.00	ST	3.81		1
13	0087 WINDSOR JUNCTION	TILTONVILLE	138.00	138.00	ST	0.30		2
14	0089 WEST PHILO EXT. NO.		138.00	138.00	WP	0.05		1
15	0090 WEST PHILO EXT. NO.		138.00	138.00	WP	0.13		1
16	0091 KAMMER	OHIO FERRO ALLOYS	138.00	138.00	WP	2.45		1
17	0091 KAMMER	OHIO FERRO ALLOYS (WV)	138.00	138.00	ST	0.71		1
18	0095 PORTSMOUTH	TRENTON NO. 1	138.00	138.00	WP	68.24		1
19	0095 PORTSMOUTH	TRENTON NO. 1	138.00	138.00	ST	1.04		1
20	0095 PORTSMOUTH	TRENTON NO. 1	138.00	138.00	ST	0.24		2
21	0096 THIVENER	BUCKEYE CO-OP	138.00	138.00	WP	6.16		1
22	0097 MERCERVILLE	APPLE GROVE	138.00	138.00	ST	5.11		2
23	0098 MILLWOOD EXT.		138.00	138.00	WP	0.10		1
24	0101 THIVENER EXT.		138.00	138.00	WP	0.09		1
25	0102 MEIGS EXT. NO. 1		138.00	138.00	WP	0.10		1
26	0103 MEIGS EXT NO. 2		138.00	138.00	WP	0.17		1
27	0108 OHIO CENTRAL	NORTH NEWARK	138.00	138.00	ST	0.33		2
28	0108 OHIO CENTRAL	NORTH NEWARK	138.00	138.00	WP	21.30		1
29	0110 NORTH STRASBURG		138.00	138.00	WP	0.06		1
30	0111 NORTH STRASBURG		138.00	138.00	WP	0.06		1
31	0112 ZANESVILLE EXT.		138.00	138.00	ST	6.48		2
32	0113 HOWARD	BUCYRUS CENTER	138.00	138.00	ST	16.30		1
33	0113 HOWARD	BUCYRUS CENTER	138.00	138.00	ST	0.27		2
34	0114 SOUTH PEMBERVILLE	FREEMONT	138.00	138.00	WP	14.18		1
35	0114 SOUTH PEMBERVILLE	FREEMONT	138.00	138.00	ST	1.29		2
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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	0115 SUMMERFIELD	BERNE	138.00	138.00	WP	3.46		1
2	0118 SOUTH COSHOCTON	WOOSTER	138.00	138.00	WP	39.51		1
3	0120 OHIO CENTRAL	COSHOCTON JCT.	138.00	138.00	ST	0.20		1
4	0120 OHIO CENTRAL	COSHOCTON JCT.	138.00	138.00	ST	14.52		2
5	0122 KAMMER	ORMET NO. 1	138.00	138.00	ST	1.71		2
6	0123 FINDLAY CENTER EXT.		138.00	138.00	ST	6.66		1
7	0125 TIDD	WEIRTON NO. 1	138.00	138.00	ST	0.41		2
8	0126 ARROYO	EAST LIVERPOOL	138.00	138.00	ST	0.15		1
9	0128 TIDD	NATRIUM	138.00	138.00	ST	0.26		1
10	0129 HOWARD	FOSTORIA	138.00	138.00	ST	0.50		1
11	0129 HOWARD	FOSTORIA	138.00	138.00	ST	44.38		2
12	0130 EAST	TEXAS EASTERN	138.00	138.00	WP	1.99		1
13	0131 KAMMER	ORMET NO. 2	138.00	138.00	ST	1.55		2
14	0133 SUNNYSIDE	WAGENHALS NO. 1	138.00	138.00	ST	1.44		1
15	0133 SUNNYSIDE	WAGENHALS NO. 1	138.00	138.00	WP	2.23		1
16	0134 TIDD	WHEELING STEEL	138.00	138.00	ST	5.12		2
17	0141 MILLBROOK	SILOAM	138.00	138.00	ST	1.60		2
18	0141 MILLBROOK	SILOAM	138.00	138.00	SP	0.05		1
19	0143 ZANESVILLE	OHIO CENTRAL	138.00	138.00	WP	10.96		1
20	0143 ZANESVILLE	OHIO CENTRAL	138.00	138.00	ST	1.87		1
21	0144 TORREY	TIMKEN	138.00	138.00	WP	0.80		1
22	0144 TORREY	TIMKEN	138.00	138.00	ST	0.86		1
23	0145 CANTON CENTRAL	TIMKEN	138.00	138.00	SP	0.74		1
24	0145 CANTON CENTRAL	TIMKEN	138.00	138.00	ST	5.52		1
25	0146 EAST LIMA	WESTMINSTER	138.00	138.00	ST	8.38		2
26	0147 SUNNYSIDE	WAGENHALS NO. 2	138.00	138.00	WP	2.21		1
27	0149 CANTON CENTRAL	WAGENHALS	138.00	138.00	ST	2.02		2
28	0151 SOUTH CANTON	TORREY	138.00	138.00	ST	1.26		1
29	0151 SOUTH CANTON	TORREY	138.00	138.00	ST	1.60		2
30	0152 MALAGA	SPEIDEL	69.00	138.00	WP	11.99		1
31	0153 BRIDGEVILLE EXT.		138.00	138.00	WP	1.88		1
32	0156 TIFFIN CENTER EXT.		138.00	138.00	WP	5.34		1
33	0156 TIFFIN CENTER EXT.		69.00	138.00	WP	1.81		2
34	0158 ROBINSON PARK	RICHLAND	138.00	138.00	WP	14.94		1
35	0159 EAST LIMA	RICHLAND	138.00	138.00	WP	27.74		1
36					TOTAL	5,513.56		403

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 2009/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	0164 FOSTORIA CENTRAL	FOSTORIA	138.00	138.00	ST	0.08		1
2	0164 FOSTORIA CENTRAL	FOSTORIA	138.00	138.00	ST	1.48		2
3	0169 SOUTH CALDWELL	SOUTH CUMBERLAND	138.00	138.00	WP	10.86		1
4	0170 HANGING ROCK EXT.		138.00	138.00	ST	4.33		1
5	0174 CANTON CENTRAL	BLUEBELL	138.00	138.00	WP	0.36		1
6	0175 CANTON CENTRAL	CLOVERDALE	138.00	138.00	WP	0.38		1
7	0176 TIDD	STEUBENVILLE	138.00	138.00	ST	7.30		1
8	0177 SOUTHWEST LIMA	STERLING	138.00	138.00	ST	5.14		2
9	0177 SOUTHWEST LIMA	STERLING	34.00	138.00	WP	0.18		2
10	0177 SOUTHWEST LIMA	STERLING	138.00	138.00	SP	0.02		1
11	0177 SOUTHWEST LIMA	STERLING	138.00	138.00	WP	0.03		1
12	0178 SOUTHWEST LIMA	WEST LIMA	138.00	138.00	ST	0.88		2
13	0180 OHIO CENTRAL EXT		138.00	138.00	WP	0.46		1
14	0181 OHIO CENTRAL EXT		138.00	138.00	WP	0.45		1
15	0182 SOUTH CANTON	WEST CANTON	138.00	138.00	SP	5.20		2
16	0182 SOUTH CANTON	WEST CANTON	138.00	138.00	ST	2.59		1
17	0182 SOUTH CANTON	WEST CANTON	138.00	138.00	ST	2.26		2
18	0183 KAMMER	WEST BELLAIRE	138.00	138.00	ST	12.85		1
19	0183 KAMMER	WEST BELLAIRE	69.00	138.00	ST	0.33		2
20	0186 EAST ZANESVILLE		138.00	138.00	WP	0.04		1
21	0187 WEST BELLAIRE	BRUES	138.00	138.00	ST	4.26		1
22	0188 WEST BELLAIRE	TILTONVILLE	138.00	138.00	WP	11.49		1
23	0188 WEST BELLAIRE	TILTONVILLE	138.00	138.00	ST	0.50		1
24	0189 CROOKSVILLE TIE		138.00	138.00	WP	0.20		1
25	0190 SOUTHWEST LIMA	WEST MOULTON	138.00	138.00	WP	13.33		1
26	0193 TIFFIN CENTER	FREMONT CENTER	138.00	138.00	WP	11.84		1
27	0193 TIFFIN CENTER	FREMONT CENTER	138.00	138.00	ST	0.70		1
28	0193 TIFFIN CENTER	FREMONT CENTER	138.00	138.00	ST	0.04		2
29	0196 FREMONT CENTER	FREMONT	138.00	138.00	WP	3.02		1
30	0196 FREMONT CENTER	FREMONT	138.00	138.00	ST	2.68		1
31	0198 N. PROCTORVILLE	EAST HUNTINGTON	138.00	138.00	ST	3.86		1
32	0198 N. PROCTORVILLE	EAST HUNTINGTON	34.00	138.00	ST	0.08		2
33	0200 CAMPBELL ROAD	MIDWEST CO-OP	138.00	138.00	WP	0.15		1
34	0201 N. PROCTORVILLE	SOUTH POINT	138.00	138.00	ST	0.04		1
35	0201 N. PROCTORVILLE	SOUTH POINT	138.00	138.00	ST	10.83		2
36					TOTAL	5,513.56		403

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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	0202 MUSKINGUM	WOLF CREEK	138.00	138.00	WP	4.37		1
2	0202 MUSKINGUM	WOLF CREEK	138.00	138.00	ST	0.34		1
3	0203 SWITZER EXT. NO. 1		138.00	138.00	WP	0.04		1
4	0204 SWITZER EXT. NO. 2		138.00	138.00	WP	0.06		1
5	0210 BUCKLEY ROAD EXT.		138.00	138.00	SP	0.09		1
6	0210 BUCKLEY ROAD EXT.		138.00	138.00	WP	2.62		1
7	0213 WINDSOR EXT. NO. 2			138.00	WP	0.11		1
8	0221 DARRAH	NORTH PROCTORVILLE	138.00	138.00	ST	3.51		1
9	0223 DEXTER	MEIGS NO. 2	138.00	138.00	WP	5.53		1
10	0224 NORTH RUTLAND	MEIGS NO. 1	138.00	138.00	WP	3.84		1
11	0225 AMITY	ACADEMIA	138.00	138.00	ST	0.14		1
12	0225 AMITY	ACADEMIA	138.00	138.00	ST	6.33		2
13	0226 ACADEMIA	WEST MT. VERNON	138.00	138.00	ST	0.15		2
14	0226 ACADEMIA	WEST MT. VERNON	138.00	138.00	ST	5.95		1
15	0229 CANNELVILLE	GURNSEY MUSKINGUM C	138.00	138.00	WP	0.11		1
16	0230 FAIRCREST EXT.		138.00	138.00	SP	0.04		1
17	0235 WEST MILLERSPORT	HEATH	138.00	138.00	WP	11.85		1
18	0235 WEST MILLERSPORT	HEATH	138.00	138.00	ST	0.16		1
19	0238 NORTH	EXTENSION	138.00	138.00	ST	3.54		1
20	0240 NORTH CROWN CITY		138.00	138.00	WP	0.24		1
21	0241 NORTH CROWN CITY		138.00	138.00	WP	0.24		1
22	0242 HEATH EXT. NO. 2		138.00	138.00	ST	1.29		1
23	0243 HEATH EXT. NO. 1		138.00	138.00	ST	1.29		1
24	0244 EAST SIDE EXT.		138.00	138.00	WP	0.24		2
25	0244 EAST SIDE EXT.		138.00	138.00	ST	0.08		2
26	0245 SOUTHEAST CANTON	SUNNYSIDE	138.00	138.00	ST	2.31		2
27	0247 SOUTHEAST CANTON	WACO	138.00	138.00	ST	2.12		2
28	0252 WEST DOVER EXT.		138.00	138.00	WP	0.10		1
29	0253 WEST DOVER EXT.		138.00	138.00	WP	0.09		1
30	0254 BUCKEYE CO-OP EXT.		138.00	138.00	WP	0.21		1
31	0257 GREENLAWN EXT.		138.00	138.00	WP	1.09		2
32	0260 EAST PROCTORVILLE		138.00	138.00	ST	0.13		2
33	0264 FREMONT	SANDUSKY BAY	69.00	138.00	WP	12.13		1
34	0265 WEST DOVER	SUGARCREEK	138.00	138.00	WP	4.07		1
35	0267 NORTH PORTSMOUTH	CENTRAL PORTSMOUTH	138.00	138.00	WP	6.04		1
36					TOTAL	5,513.56		403

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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	0273 BUCKLEY ROAD	FREMONT CENTER	69.00	138.00	WP	0.90		2
2	0274 WAYVIEW	HOOVER NORTH	69.00	138.00	ST	0.02		1
3	0274 WAYVIEW	HOOVER NORTH	69.00	138.00	ST	1.04		2
4	0275 WEST CANTON JCT.	WAYVIEW	138.00	138.00	WP	1.11		1
5	0275 WEST CANTON JCT.	WAYVIEW	138.00	138.00	SP	1.80		2
6	0275 WEST CANTON JCT.	WAYVIEW	138.00	138.00	ST	1.89		1
7	0276 BELDEN VILLAGE EXT.		138.00	138.00	SP	1.51		1
8	0280 EAST AMSTERDAM	CARROLL CO-OP	69.00	138.00	WP	7.98		1
9	0282 SOUTH POINT TIE		138.00	138.00	WP	0.09		1
10	0286 WEST CANTON TIE		138.00	138.00	SP	0.07		2
11	0289 OHIO CENTRAL EXT.		138.00	138.00	WP	0.27		1
12	0290 SOUTH CANTON EXT.		138.00	138.00	ST	0.71		2
13	0294 SOUTH CANTON EXT.		138.00	138.00	ST	0.31		2
14	0295 BROADACRE EXT.		138.00	138.00	SP	0.04		2
15	0307 WEST VAN WERT	DELPHOS CENTER	69.00	138.00	WP	1.70		1
16	0313 BUCKEYE COOP EXT.		138.00	138.00	WP	0.85		1
17	0316 ORDANANCE JCT.		138.00	138.00	SP	0.10		2
18	0317 GUERNSEY	MUSKINGUM CO-OP EXT.	138.00	138.00	WP	0.12		1
19	0318 BUCKEYE CO-OP EXT.		138.00	138.00	WP	0.15		1
20	0320 HEDDING ROAD	MORROW CO-OP	138.00	138.00	WP	0.09		1
21	0324 WEST MILLERSPORT	SOUTH CENTRAL POWER	138.00	138.00	WP	0.20		1
22	0325 SHELBY MUNICIPAL		138.00	138.00	ST	0.53		1
23	0326 BLOOMFIELD	GUERNSEY MUSKINGUM C	138.00	138.00	WP	0.41		1
24	0327 NORTH CENTRAL		138.00	138.00	WP	0.45		1
25	0328 NORTH CHESIRE	EXTENSION NO. 2	138.00	138.00				
26	0329 TYCOON EXT.		138.00	138.00	WP	0.29		1
27	0331 LICKING CO-OP EXT.		138.00	138.00	WP	0.04		1
28	0333 ASHLEY EXT		69.00	138.00	WP	0.62		1
29	0334 NORTH CHESIRE	EXTENTION NO. 1	138.00	138.00	ST	0.38		2
30	0336 SHUFFEL ROAD	TIMKEN RESEARCH	69.00	138.00	ST	0.66		1
31	0337 TIMKEN, RICHVILLE EX		138.00	138.00	WP	1.11		2
32	0338 CONESVILLE COAL		138.00	138.00	WP	0.63		1
33	0339 A.G.A. GAS EXT.		138.00	138.00	WP	0.16		1
34	0342 EAST WOOSTER EXT.		138.00	138.00	ST	5.15		2
35	0343 EAST WOOSTER EXT.		138.00	138.00	WP	0.18		1
36					TOTAL	5,513.56		403

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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	0343 EAST WOOSTER EXT.		138.00	138.00	WP	0.43		2
2	0344 WAGENHALS	LTV STEEL NO. 1	138.00	138.00	ST	0.65		1
3	0345 WAGENHALS	LTV STEEL NO. 2	138.00	138.00	ST	0.68		1
4	0346 FOSTORIA TIE		138.00	138.00	WP	0.02		1
5	0347 FOSTORIA CENTRAL		138.00	138.00	ST	0.10		2
6	0348 FOSTORIA CENTRAL		138.00	138.00	ST	0.10		1
7	0349 FOSTORIA POWER		138.00	138.00	ST	0.10		3
8	0350 HANCOCK WOOD		138.00	138.00	WP	0.03		1
9	0351 EAST LEIPSIC EXT		138.00	138.00	SP	6.57		2
10	0352 BUCKEYE CO-OP EXT		138.00	138.00	WP	0.09		1
11	0353 STERLING	FOUNDRY PARK	138.00	138.00	WP	0.91		1
12	0354 GAVIN EXT. NO. 1		138.00	138.00	ST	3.10		2
13	0355 GAVIN EXT. NO. 2		138.00	138.00	ST	3.01		2
14	0358 LICKING REC. EXT. A		138.00	138.00	WP	0.24		1
15	0359 BUCKHORN	HOLMES	138.00	138.00	WP	0.98		1
16	0360 ADAMS RUAL	EMERALD	138.00	138.00	WP	0.80		1
17	0361 RILEY CREEK	PAULDING PUTNAM	138.00	138.00	ST	1.20		1
18	0363 MEIGS NO. 2	WILKESVILLE	138.00	138.00		1.60		1
19	0364 NORTH CENTRAL		138.00	138.00		1.84		1
20	0368 BALL HOLLOW	WASHINGTON CO-OP	138.00	138.00		0.05		1
21	0371 SPENCER RIDGE	BUCKINGHAM COAL	138.00	138.00	WP	0.12		1
22	0370 BUCKEYE CO-OP EXT		138.00	138.00	ST	0.10		2
23	0372 NORTH BELLVILLE		138.00	138.00	WP	0.11		2
24	0375 HANTHORN RD	G.O. ETHANOL		138.00	ST	0.34		1
25	0376 WARNER EXT.	SUNNYSIDE - TORREY	138.00	138.00	WP	0.30		1
26	0377 YELLOWBUSH		138.00	138.00	ST	0.04		1
27	LINES < 132KV					2,529.16		
28								
29								
30	EXPENSES 765KV LINES							
31	EXPENSES 345KV LINES							
32	EXPENSES 138KV LINES							
33	EXPENSES <132KV LINES							
34								
35								
36					TOTAL	5,513.56		403

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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)	
954 ACSR	1,876,001	8,494,837	10,370,838					1
954 ACSR								2
954 ACSR	9,945,335	42,593,225	52,538,560					3
954 ACSR								4
1351.5 AC	204,407	1,682,341	1,886,748					5
1351.5 AC	7,365,293	24,049,838	31,415,131					6
1351.5 AC		314,184	314,184					7
1351.5 AC	494,510	1,172,835	1,667,345					8
1351.5 AC	9,344,715	45,510,757	54,855,472					9
1351.5 AC								10
1351.5 AC	1,462,777	10,327,662	11,790,439					11
1351.5 AC	650,192	3,816,469	4,466,661					12
1275 ACSR	259,060	2,749,838	3,008,898					13
2303 ACAR	1,255,207	5,718,649	6,973,856					14
2303 ACAR								15
1275 ACSR	737,119	8,787,117	9,524,236					16
2303 ACAR								17
1275 ACSR	429,503	2,556,148	2,985,651					18
1414 ACSR	1,075,707	7,182,307	8,258,014					19
1414 ACSR	1,104	15,200	16,304					20
1414 ACSR								21
954 ACSR	914,992	3,698,427	4,613,419					22
954 ACSR								23
954 ACSR	234,114	590,726	824,840					24
954 ACSR								25
954 ACSR								26
1414 ACSR	442,149	2,316,001	2,758,150					27
954 ACSR								28
1414 ACSR	518	30,806	31,324					29
1414 ACSR								30
954 ACSR	1,678,273	8,775,482	10,453,755					31
954 ACSR								32
954 ACSR	1,073,666	3,408,432	4,482,098					33
954 ACSR								34
954 ACSR	418,163	3,316,084	3,734,247					35
	70,400,633	427,032,253	497,432,886	376,194	7,913,147		8,289,341	36

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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.
	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
954 ACSR	15,472	471,939	487,411					1
954 ACSR	20,410	182,467	202,877					2
1414 ACSR	513,253	2,311,352	2,824,605					3
954 ACSR	443,997	1,523,163	1,967,160					4
954 ACSR								5
954 ACSR	999	225,879	226,878					6
1275 ACSR	108,893	1,111,112	1,220,005					7
2303 ACAR	186,006	998,934	1,184,940					8
954 ACSR	512,626	4,308,481	4,821,107					9
		1,756,284	1,756,284					10
								11
397.5 ACS	121,902	759,562	881,464					12
397.5 ACS								13
397.5 ACS	20,508	79,591	100,099					14
397.5 ACS								15
556.5 ACS	382,811	1,704,835	2,087,646					16
636 ACSR								17
556.5 ACS	6,308	7,773	14,081					18
556.5 ACS	305,134	1,789,420	2,094,554					19
556.5 ACS								20
336.4 ACS	59,421	336,284	395,705					21
477 ACSR								22
556.5 ACS								23
397.5 ACS	138,617	1,566,455	1,705,072					24
397.5 ACS	2,514	19,200	21,714					25
1033.5 AC								26
397.5 ACS	63,306	511,378	574,684					27
1033.5 AC		-2,697	-2,697					28
1033.5 AC	214,121	1,224,049	1,438,170					29
477 ACSR	259,966	1,786,272	2,046,238					30
477 ACSR								31
6X477 ACS								32
397.5 ACS	4,691	2,279	6,970					33
397.5 ACS	10,001	125,971	135,972					34
397.5 ACS	152,649	1,204,599	1,357,248					35
	70,400,633	427,032,253	497,432,886	376,194	7,913,147		8,289,341	36

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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)	
397.5 ACS								1
477 ACSR	292,599	1,458,272	1,750,871					2
477 ACSR								3
477 ACSR	106,703	749,406	856,109					4
397.5 ACS	101,265	701,017	802,282					5
397.5 ACS								6
397.5 ACS	69,643	325,534	395,177					7
477 ACSR	84,396	568,108	652,504					8
477 ACSR								9
397.5 ACS	119,954	650,681	770,635					10
397.5 ACS								11
795 ACSR								12
397.5 ACS	31,776	214,368	246,144					13
556.5 ACS	157,804	855,468	1,013,272					14
636 ACSR	151,470	744,025	895,495					15
556.5 ACS	124,221	790,550	914,771					16
397.5 ACS	157,978	1,302,423	1,460,401					17
397.5 ACS								18
397.5 ACS								19
556.5 ACS	218,662	878,826	1,097,488					20
477 ACSR	405,614	2,435,801	2,841,415					21
336.4 ACS	121,468	1,466,244	1,587,712					22
477 ACSR								23
397.5 ACS	96,813	1,050,502	1,147,315					24
397.5 ACS								25
336.4 ACS	58,078	325,659	383,737					26
4/0 CU.	32,604	626,511	659,115					27
556.5 ACS	288,848	859,500	1,148,348					28
556.5 ACS								29
556.5 ACS								30
1033.5 AC		32,552	32,552					31
556.5 ACS	337,756	449,148	786,904					32
795 ACSR								33
556.5 ACS		130,650	130,650					34
477 ACSR	96,329	397,389	493,718					35
	70,400,633	427,032,253	497,432,886	376,194	7,913,147		8,289,341	36

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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)	
200 CU	403,916	3,019,209	3,423,124					1
556.5 ACS	116,789	191,733	308,522					2
556.5 ACS								3
219.9 ACS	36,985	69,595	106,580					4
556.5 ACS								5
795 ACSR	39,729	195,053	234,782					6
636 ACSR	77,618	760,253	837,872					7
1780 ACSR	50,235	259,764	309,999					8
336.4 ACS	61,796	479,956	541,752					9
397.5 ACS	5,312	44,276	49,588					10
795 ACSR	74,582	270,881	345,463					11
556.5 ACS	45,654	230,649	276,303					12
556.5 ACS								13
397.5 ACS	592	6,287	6,879					14
397.5 ACS								15
556.5 ACS	22,177	94,664	116,841					16
556.5 ACS								17
477 ACSR	392,562	3,323,925	3,716,487					18
477 ACSR								19
477 ACSR								20
219.9 ACS	38,610	313,010	351,620					21
397.5 ACS	40,620	478,717	519,337					22
500 CU.		2,786	2,786					23
219.9 ACS		2,576	2,576					24
219.9 ACS	891	40,208	41,099					25
219.9 ACS	1,207	5,193	6,400					26
397.5 ACS	182,781	927,368	1,110,149					27
556.5 ACS								28
1033.5 AC		5,723	5,723					29
1033.5 AC	83	6,965	7,048					30
336.4 ACS	19,512	104,084	123,596					31
556.5 ACS	222,508	411,368	633,876					32
556.5 ACS								33
556.5 ACS	156,468	437,548	594,016					34
556.5 ACS								35
	70,400,633	427,032,253	497,432,886	376,194	7,913,147		8,289,341	36

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(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
4/0 ACSR	13,905	214,251	228,156					1
477 ACSR	304,837	1,281,804	1,586,641					2
556.5 ACS	132,152	815,461	947,613					3
636 ACSR								4
1033.5 AC	10,607	134,568	145,175					5
556.5 ACS	121,176	366,395	487,571					6
556.5 ACS	6,527	35,909	42,436					7
556.5 ACS	4,128	25,660	29,788					8
556.5 ACS	1,423	35,982	37,405					9
397.5 ACS	7,029	309,640	316,669					10
397.5 ACS								11
4/0 ACSR	14,193	131,571	145,764					12
1033.5 AC	9,540	128,327	137,867					13
1033.5 AC	123,707	198,706	322,413					14
397.5 ACS								15
556.5 ACS	136,465	280,302	416,767					16
556.5 ACS	49,080	146,231	195,311					17
954 ACSR								18
556.5 ACS	312,373	740,749	1,053,122					19
556.5 ACS								20
1033.5 AC	5,655	208,367	214,022					21
1033.5 AC								22
1033.5 AC	124,081	577,566	701,647					23
636 ACSR								24
636 ACSR	201,012	473,121	674,133					25
397.5 ACS		67,143	67,143					26
1033.5 AC	1,585	337,042	338,627					27
1780 ACSR	7,157	339,849	347,006					28
556.5 ACS								29
556.5 ACS	108,181	320,909	429,090					30
336.4 ACS	17,128	78,877	96,005					31
556.5 ACS	90,342	236,857	327,199					32
556.5 ACS								33
636 ACSR	121,928	382,327	504,255					34
636 ACSR	355,024	1,202,143	1,557,167					35
	70,400,633	427,032,253	497,432,886	376,194	7,913,147		8,289,341	36

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1033.5 AC	17,527	388,100	405,627					1
1033.5 AC								2
556.5 ACS	76,201	317,408	393,609					3
636 ACSR	69,853	306,918	376,771					4
795 ACSR	1,607	23,414	25,021					5
795 ACSR	874	23,807	24,681					6
795 ACSR	95,789	460,852	556,641					7
1590 ACSR	169,056	1,210,676	1,379,732					8
4/0 CU.								9
556.5 ACS								10
556.5 ACS								11
556.5 ACS		55,737	55,737					12
556.5 ACS	375	18,926	19,301					13
556.6 ACS	199	19,571	19,770					14
795 ACSR	545,298	1,085,331	1,630,629					15
795 ACSR								16
795 ACSR								17
1033.5 AC	278,550	1,260,929	1,539,479					18
954 ACSR								19
556.5 ACS		4,938	4,938					20
556.5 ACS	175,209	411,938	587,147					21
795 ACSR	330,224	840,523	1,170,747					22
795 ACSR								23
556.5 ACS	868	10,088	10,956					24
636 ACSR	130,175	432,118	562,293					25
556.5 ACS	256,571	781,047	1,037,618					26
556.5 ACS								27
795 ACSR								28
795 ACSR	128,757	568,711	697,468					29
795 ACSR								30
795 ACSR	217,008	697,254	914,262					31
795 ACSR								32
336.4 ACS	7,295	6,963	14,258					33
795 ACSR	387,022	1,465,883	1,852,905					34
795 ACSR								35
	70,400,633	427,032,253	497,432,886	376,194	7,913,147		8,289,341	36

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556.5 ACS	29,168	165,783	194,951					1
636 ACSR								2
556.5 ACS		5,580	5,580					3
556.5 ACS		6,304	6,304					4
795 ACSR	51,056	455,408	506,464					5
795 ACSR								6
	232	9,417	9,649					7
1033.5 AC	36,957	516,508	553,465					8
556.5 ACS	70,644	209,263	279,907					9
556.5 ACS	48,250	152,211	200,461					10
556.5 ACS	173,198	411,482	584,680					11
795 ACSR								12
556.5 ACS	40,795	538,178	578,973					13
795 ACSR								14
336.4 ACS	697	19,745	20,442					15
1033.5 AC		7,504	7,504					16
795 ACSR	369,312	598,799	968,111					17
795 ACSR								18
556.5 ACS	78,186	260,728	338,914					19
556.5 ACS	2,168	14,035	16,203					20
556.5 ACS	2,276	18,225	20,501					21
795 ACSR	112,231	101,538	213,769					22
556.5 ACS	37,817	42,712	80,529					23
795 ACSR	23,316	101,341	124,657					24
795 ACSR								25
1033.5 AC	214,206	625,085	839,291					26
1033.5 AC	194,250	520,019	714,269					27
1033.5 AC		12,561	12,561					28
1033.5 AC	348	6,084	6,432					29
556.5 ACS	2,627	21,827	24,454					30
795 ACSR	29,329	97,211	126,540					31
1033.5 AC	3,146	46,469	49,615					32
795 ACSR	522,464	1,341,778	1,864,242					33
795 ACSR	317,328	266,194	583,522					34
795 ACSR	141,040	642,102	783,142					35
	70,400,633	427,032,253	497,432,886	376,194	7,913,147		8,289,341	36

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(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
556.5 ACS	27,304	249,067	276,371					1
795 ACSR	24,583	397,019	421,602					2
795 ACSR								3
795 ACSR	94,695	1,164,921	1,259,616					4
795 ACSR								5
795 ACSR								6
795 ACSR	133,378	354,325	487,703					7
795 ACSR	284,961	931,508	1,216,469					8
795 ACSR		12,090	12,090					9
795 ACSR	135,135	267,143	402,278					10
636 ACSR		15,828	15,828					11
1033.5 AC	12,103	105,405	117,508					12
1033.5 AC	27,213	118,561	145,774					13
1780 ACSR		43,415	43,415					14
795 ACSR	30,533	162,383	192,916					15
556.5 ACS	19,405	93,826	113,231					16
1590 ACSR		13,046	13,046					17
556.5 ACS	974	41,700	42,674					18
556.5 ACS	21,636	29,443	51,079					19
795 ACSR	8	40,513	40,521					20
556.5 ACS		33,801	33,801					21
336.4 ACS								22
336.4 ACS	5,181	96,269	101,450					23
336.4 ACS	26,148	87,090	113,238					24
	4,300		4,300					25
556.5 ACS	20,171	80,661	100,832					26
336.4 ACS	940	22,202	23,142					27
336.4 ACS	86,963	112,471	199,434					28
1033.5 AC	16,571	79,950	96,521					29
795 ACSR	4,001	175,402	179,403					30
1033.5 AC	153,330	548,818	702,148					31
1033.5 AC	21,917	141,203	163,120					32
336.4 ACS	4,230	215,197	219,427					33
556.5 ACS	57,693	205,160	262,853					34
795 ACSR	16,134	206,825	222,959					35
	70,400,633	427,032,253	497,432,886	376,194	7,913,147		8,289,341	36

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 2009/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
795 ACSR								1
1033.5 AC	67,527	101,885	169,412					2
1033.5 AC	1,568	118,175	119,743					3
336.4 ACS								4
1033.5 AC	3,617	45,851	49,468					5
1033.5 AC	10,877	59,075	69,952					6
336.4 ACS								7
556.5 ACS		12,614	12,614					8
795 ACSR	491,697	2,945,947	3,437,644					9
336.4 ACS	1,602	36,388	37,990					10
795 ACSR	7,772	74,088	81,860					11
1033.5 AC	349,666	1,509,061	1,858,727					12
1033.5 AC	190,026	1,842,620	2,032,646					13
556.5 ACS	1,275	62,153	63,428					14
336.4 ACS	75,227	300,012	375,238					15
556.5 ACS	3,853	227,025	230,878					16
336.4 ACS		372,700	372,700					17
	9,000	96,880	105,880					18
556.5 ACS	217,676	532,226	749,903					19
556.5 ACS		7,549	7,549					20
4/0 ACSR	-1	-41,451	-41,451					21
397.5 ACS		34,918	34,918					22
556.5 ACS		225,220	225,220					23
556.5 ACS		48,557	48,557					24
397.5 ACS								25
795 ACSR		65	65					26
	11,619,992	145,894,101	157,514,092					27
								28
								29
				34,571	727,196		761,767	30
				44,302	931,887		976,189	31
				124,754	2,624,172		2,748,926	32
				172,567	3,629,892		3,802,459	33
								34
								35
	70,400,633	427,032,253	497,432,886	376,194	7,913,147		8,289,341	36

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 2009/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)	(c)	Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
1	No New Lines						
2							
3	Lines Altered						
4	0005 Windsor	Canton	0.01	ST		1	1
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
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37							
38							
39							
40							
41							
42							
43							
44	TOTAL		0.01			1	1

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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
200 cm	Copper7		138		221,923	29,604		251,527	4
									5
									6
									7
									8
									9
									10
									11
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									40
									41
									42
									43
					221,923	29,604		251,527	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 2009/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	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	ACADEMIA-OH	T	138.00	69.00	13.00
2		T	69.00		
3	ADA-OH	D	69.00	13.09	
4	ANCHOR HOCKING (OP)-OH	D	69.00	12.00	
5		D	69.00	4.00	
6		D	34.50	4.00	
7	ANTWERP-OH	D	69.00	12.47	
8	APPLE CREEK-OH	D	138.00	13.09	
9	ASH AVENUE-OH	D	34.50	13.09	
10	AUGLAIZE-OH	D	69.00	13.09	
11	AVONDALE-OH	D	69.00	12.00	
12	BANNOCK ROAD-OH	D	69.00	12.00	
13	BARNESVILLE-OH	D	69.00	13.09	
14	BEALL AVENUE-OH	D	69.00	13.09	
15		D	69.00	4.00	
16	BEAVER-OH	D	69.00	34.50	12.00
17		D	69.00	12.00	
18	BELDEN VILLAGE-OH	D	138.00	13.09	
19	BERLIN (OP)-OH	D	69.00	34.50	
20		D	69.00	13.09	
21	BERWICK-OH	D	69.00	13.09	
22	BILLIAR-OH	D	69.00	13.09	
23		D	69.00	12.00	
24	BLACKJACK ROAD-OH	D	69.00	12.00	
25	BLISS PARK-OH	D	69.00	12.00	
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	12.00	
30		D	69.00	4.00	
31	BRIDGEVILLE-OH	D	138.00	13.09	
32	BROOM ROAD-OH	D	69.00	13.09	
33	BUCKLEY ROAD-OH	T	138.00	69.50	13.09
34	BUCYRUS-OH	D	69.00	13.09	
35		D	69.00		
36	BUCYRUS CENTER-OH	T	138.00	69.50	13.09
37		T	69.00	13.09	
38	BYESVILLE-OH	D	69.00	12.00	
39	CADIZ-OH	D	69.00	13.09	
40	CALCUTTA-OH	D	69.00	13.09	

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SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	CALDWELL-OH	T	138.00	34.50	
2		T	138.00	13.09	
3	CAMBRIDGE-OH	D	34.50	12.00	
4		D	34.50	4.00	
5		D	34.50		
6	CANAL ROAD-OH	T	138.00	69.00	34.50
7	CANTON CENTRAL-OH	T	345.00	138.00	12.00
8	CARROLLTON-OH	D	138.00	13.09	
9	CENTER STREET-OH	D	69.00	12.00	
10	CENTRAL PORTSMOUTH-OH	T	138.00	69.00	34.50
11		T	69.00	7.20	
12	CHATFIELD-OH	T	138.00	69.50	13.09
13	CHERRY AVENUE-OH	D	69.00	12.00	
14	CLIFTMONT AVENUE-OH	D	69.00	12.00	
15	COLUMBUS GROVE-OH	D	69.00	12.47	
16	CONESVILLE PREPARATION PLANT-OH	D	138.00	13.09	
17	COOPERMILL-OH	D	69.00	13.09	
18		D	69.00	4.00	
19		D	69.00		
20	COSHOCTON-OH	D	69.00	12.00	
21		D	69.00	4.00	
22		D	69.00		
23	CRESTWOOD-OH	D	34.50	13.09	
24	CROOKSVILLE-OH	T	138.00	69.00	12.00
25		T	69.00	13.09	
26		T	69.00	4.00	
27	DELPHOS-OH	D	69.00	13.09	
28	DENNISON-OH	T	69.00	34.50	
29		T	69.00	12.00	
30		T	69.00		
31		T	34.50	4.00	
32	DOGWOOD RIDGE-OH	D	138.00	13.09	
33	DON MARQUIS (OP-CS) (OVEC)-OH	T	765.00	345.00	34.50
34		T	345.00		
35		T	345.00	138.00	13.80
36	DOW CHEMICAL-HANGING ROCK-OH	D	69.00	12.00	
37	DRESDEN-OH	D	69.00	12.00	
38	DUNKIRK (OP)-OH	T	69.00	36.20	
39		T	69.00	13.09	
40		T	69.00		

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SUBSTATIONS

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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	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	EAST AMSTERDAM-OH	T	138.00	69.00	12.00
2	EAST BEAVER-OH	T	138.00	69.00	34.50
3	EAST CAMBRIDGE-OH	T	69.00	34.50	
4		T	69.00		
5	EAST CANTON-OH	D	69.00	12.00	
6	EAST FREMONT-OH	D	69.00	13.09	
7		D	69.00	4.36	
8	EAST LANCASTER-OH	D	69.00	12.00	
9		D	69.00		
10	EAST LEIPSIC-OH	T	138.00	69.50	7.20
11		T	138.00		
12		T	69.00	36.20	
13	EAST LIMA-OH	T	345.00	137.50	13.20
14		T	345.00	137.50	13.14
15		T	138.00	69.50	13.09
16		T	138.00		
17	EAST LIVERPOOL-OH	T	138.00	70.50	13.09
18		T	69.00		
19	EAST LOGAN-OH	D	69.00	12.00	
20		D	69.00		
21	EAST NEWARK-OH	D	69.00	12.00	
22		D	69.00	4.00	
23	EAST OTTAWA-OH	T	69.00	13.09	
24		T	69.00		
25	EAST POINTE-OH	D	138.00	13.09	
26	EAST PROCTORVILLE-OH	D	138.00	34.50	
27	EAST SIDE (LIMA)-OH	D	138.00	36.20	
28		D	34.50	4.33	
29	EAST SPARTA-OH	D	23.00	12.00	
30		D	23.00		
31	EAST TIFFIN-OH	D	69.00	13.09	
32	EAST UNION-OH	D	69.00	13.09	
33	EAST WILLARD-OH	D	69.00	13.09	
34	EAST WOOSTER-OH	T	138.00	69.50	13.09
35		T	138.00	23.00	
36		T	138.00	13.09	
37		T	138.00		
38	EAST ZANESVILLE-OH	T	138.00	69.00	13.00
39		T	138.00	69.00	12.00
40		T	138.00		

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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	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	EASTON STREET-OH	D	69.00	13.09	
2	EASTOWN ROAD-OH	D	138.00	13.20	
3		D	138.00	13.09	
4	EIGHTEEN STREET HEIGHTS-OH	D	69.00	12.00	
5	ELIZABETH STREET-OH	D	34.50	4.36	
6	ETNA-OH	D	69.00	34.50	
7		D	69.00	13.09	
8	FAIRCREST STREET-OH	D	138.00	13.09	
9	FAIRDALE-OH	D	69.00	12.00	
10	FAIRFIELD-OH	D	69.00	4.36	
11	FINDLAY-OH	D	34.50	13.09	
12		D	34.50		
13	FINDLAY CENTER-OH	T	138.00	69.50	35.00
14		T	34.50	13.09	
15		T	34.50		
16	FOREST (OP)-OH	T	69.00	23.99	4.16
17		T	69.00	23.50	
18		T	69.00	13.09	
19		T	69.00		
20	FOSTORIA CENTRAL-OH	T	345.00	137.50	13.80
21	FREDERICKTOWN-OH	D	69.00	13.09	
22	FREMONT (OP)-OH	T	138.00	69.50	13.09
23		T	69.00		
24	FREMONT CENTER-OH	T	138.00	70.50	13.09
25		T	138.00		
26		T	69.00	13.09	
27		T	69.00		
28	GAMBIER-OH	D	69.00	12.00	
29	GAVIN-OH	T	765.00	69.00	
30		T	138.00		
31		T	138.00	69.00	12.00
32		T	69.00	12.00	
33	GLENMOOR-OH	D	69.00	12.00	
34	GRANVILLE-OH	D	69.00	13.09	
35		D	69.00	12.00	
36	GREELY-OH	D	69.00	13.09	
37		D	69.00	4.36	
38	GREENLAWN-OH	T	138.00	69.50	13.09
39	GREER-OH	T	69.00	35.00	
40		T	34.50	12.00	

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SUBSTATIONS

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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	HAMMONDSVILLE-OH	T	69.00	23.00	
2		T	69.00	12.00	
3	HANGING ROCK-OH	T	765.00		
4		T	138.00	69.00	34.50
5	HARPSTER-OH	T	69.00	35.00	
6	HAVILAND-OH	T	138.00	69.50	13.09
7		T	138.00	69.00	34.65
8		T	138.00	13.09	
9	HEATH-OH	T	138.00	69.00	12.00
10		T	138.00	34.50	
11		T	69.00	4.00	
12	HIGHLAND AVENUE-OH	D	69.00	13.09	
13	HIGHLAND TERRACE-OH	D	69.00	12.00	
14	HOCKING-OH	T	138.00	69.00	12.00
15	HOWARD-OH	T	138.00	69.50	11.00
16		T	138.00		
17		T	69.00	13.09	
18		T	69.00		
19	HUGHES STREET-OH	D	69.00	4.36	
20	KALIDA-OH	T	69.00	35.00	
21		T	69.00	13.09	
22		T	69.00		
23	KAMMER 138KV-WV	T	138.00		
24	KAMMER 345KV-WV	T	345.00	138.00	13.80
25		T	345.00	138.00	13.00
26	KAMMER 400 YARD-WV	T	765.00	345.00	34.50
27	KAMMER 765-500KV-WV	T	765.00		
28	KENTON-OH	D	69.00	36.20	
29		D	69.00		
30	LANCASTER-OH	D	69.00	12.00	
31		D	69.00	4.00	
32		D	69.00		
33	LANCASTER JUNCTION-OH	D	69.00	13.09	
34		D	69.00	12.00	
35	LEESVILLE (OP)-OH	D	69.00	13.09	
36		D	69.00	12.00	
37	LEIPSIC-OH	D	69.00	13.09	
38	LINDEN AVENUE-OH	D	69.00	12.00	
39		D	69.00	4.00	
40		D	69.00		

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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	LOCK SEVENTEEN-OH	D	69.00	13.00	
2		D	69.00		
3	LOUISVILLE-OH	D	69.00	12.00	
4	MAHONING ROAD-OH	D	69.00	12.00	
5	MALVERN-OH	T	138.00	69.00	12.00
6		T	138.00	23.00	12.00
7		T	23.00	12.00	
8	MARTINS FERRY-OH	D	69.00	12.00	
9	MARTINSBURG ROAD-OH	D	69.00	13.09	
10	MARYSVILLE-OH	T	765.00		
11		T	765.00	345.00	34.50
12		T	765.00	345.00	12.00
13	MAULE ROAD-OH	D	69.00	13.09	
14	MCCOMB (OP)-OH	D	34.50	13.09	
15	MEIGS NO. 1-OH	D	138.00	34.50	
16	MEIGS NO. 2-OH	D	138.00	34.50	
17	MEMORIAL DRIVE-OH	D	69.00	13.09	
18	MILL STREET-OH	D	69.00	12.00	
19	MILLBROOK PARK-OH	T	138.00	69.00	34.50
20		T	138.00	34.50	11.00
21		T	138.00		
22		T	34.50	12.00	
23	MILLWOOD-OH	D	138.00	13.09	
24	MINERVA-OH	D	69.00	13.09	
25	MINFORD-OH	D	69.00	12.00	
26	MONROE STREET-OH	D	69.00	12.00	
27	MOUNT VERNON (OP)-OH	D	69.00	12.00	
28		D	69.00	4.00	
29	MUSKINGUM RIVER 138KV-OH	T	345.00	138.00	13.00
30		T	345.00	138.00	12.00
31		T	138.00	69.00	13.09
32	NEGLEY-OH	D	138.00	13.09	
33	NEW LEXINGTON-OH	D	69.00	13.09	
34		D	69.00		
35	NEW LIBERTY-OH	T	138.00	70.50	36.20
36		T	138.00	34.50	
37		T	138.00	13.09	
38		T	138.00		
39		T	34.50		
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 2009/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	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	NEW PHILADELPHIA-OH	D	69.00	34.50	
2		D	69.00		
3	NEWARK-OH	D	69.00	4.36	
4		D	69.00		
5	NEWARK CENTER-OH	T	138.00	69.00	12.00
6	NEWCOMERSTOWN-OH	T	138.00	69.00	12.00
7		T	69.00	34.50	
8		T	69.00	34.50	12.00
9		T	69.00		
10	NORTH BALTIMORE-OH	D	34.50	13.09	
11		D	34.50		
12	NORTH BELLVILLE-OH	T	138.00	69.50	13.09
13		T	69.00		
14	NORTH CAMBRIDGE-OH	D	69.00	13.09	
15		D	69.00	4.36	
16	NORTH CANTON-OH	D	69.00	13.09	
17		D	69.00		
18	NORTH COSHOCTON-OH	T	69.00	34.50	12.00
19		T	69.00	12.00	
20		T	69.00		
21	NORTH CROWN CITY-OH	T	138.00	69.00	13.20
22	NORTH DELPHOS-OH	T	138.00	70.50	36.20
23		T	69.00		
24	NORTH END FOSTORIA-OH	D	69.00	13.09	
25	NORTH FINDLAY-OH	T	138.00	69.50	35.00
26		T	138.00	35.00	
27		T	138.00		
28		T	34.50		
29	NORTH FREMONT-OH	D	69.00	13.09	
30	NORTH HEBRON-OH	D	69.00	34.50	
31	NORTH HICKSVILLE-OH	D	69.00	13.09	
32	NORTH LEIPSIC-OH	D	69.00	13.09	
33	NORTH LEXINGTON-OH	D	138.00	13.09	
34	NORTH MUSKINGUM-OH	T	138.00	69.00	12.00
35	NORTH NEWARK-OH	T	138.00	69.00	4.00
36		T	138.00	13.09	
37		T	138.00		
38		T	69.00	12.00	
39		T	69.00	4.00	
40		T	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 2009/Q4

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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	NORTH PORTSMOUTH-OH	T	138.00	69.00	34.50
2	NORTH PROCTORVILLE-OH	T	765.00	138.00	13.80
3	NORTH SPENCERVILLE-OH	D	69.00	13.09	
4	NORTH UPPER SANDUSKY-OH	D	69.00	13.09	
5	NORTH WALDO-OH	T	138.00	69.00	7.20
6		T	69.00	13.09	
7	NORTH WELLSVILLE-OH	D	69.00	12.00	
8		D	69.00		
9	NORTH WILLARD-OH	D	69.00	13.09	
10		D	69.00		
11	NORTH WOODCOCK-OH	T	138.00	69.50	35.50
12		T	34.50		
13	NORTH WOOSTER-OH	D	69.00	12.00	
14	NORTH ZANESVILLE-OH	D	138.00	13.09	
15	NORTHEAST CANTON-OH	T	138.00	69.00	12.00
16		T	69.00		
17	NORTHEAST FINDLAY-OH	T	138.00	36.20	
18	NORTHWEST LIMA-OH	D	138.00	13.09	
19	NORVAL PARK-OH	D	69.00	4.00	
20	OAKLAND-OH	D	69.00	12.00	
21	OAKWOOD ROAD-OH	D	69.00	12.00	
22	OERTELS CORNERS-OH	D	69.00	12.00	
23	OHIO CENTRAL-OH	T	345.00	138.00	13.80
24		T	138.00	70.50	36.20
25		T	138.00	69.00	12.00
26		T	138.00	69.00	4.00
27		T	138.00	13.09	
28		T	69.00	34.50	
29		T	69.00	13.09	
30		T	69.00	12.00	
31		T	34.50	12.00	
32		T	23.00	12.00	
33		T	23.00	4.00	
34	PACKARD-OH	D	138.00	13.20	
35	PAULDING-OH	D	69.00	13.09	
36		D	69.00		
37	PEKIN-OH	T	69.00	23.00	
38		T	69.00	13.09	
39		T	69.00		
40	PIEDMONT AVENUE-OH	D	26.00	4.00	

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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	PITTSBURGH AVENUE-OH	D	69.00	13.09	
2	PLEASANT STREET-OH	T	69.00	34.50	
3		T	69.00		
4	PLYMOUTH HEIGHTS-OH	D	69.00	12.00	
5	POWELSON-OH	D	138.00	13.09	
6	PROMWAY-OH	D	138.00	13.09	
7	QUARRY ROAD-OH	D	69.00	12.00	
8	RACINE HYDRO-OH	T	69.00	13.09	
9	RALSTON-OH	D	69.00	12.00	
10	REEDURBAN-OH	T	138.00	69.00	12.00
11		T	138.00	13.09	
12	RIVERVIEW (OP)-OH	D	69.00	13.09	
13		D	69.00	4.36	
14		D	69.00		
15	ROBB AVENUE-OH	D	34.50	4.00	
16	ROCKHILL (OP)-OH	T	138.00	35.00	
17		T	138.00	34.65	11.00
18		T	138.00	13.09	
19		T	34.50	13.09	
20		T	34.50	4.36	
21		T	34.50		
22	ROSEMOUNT-OH	D	69.00	34.50	
23		D	69.00	13.09	
24	RUTLAND-OH	T	138.00	34.50	
25	SAINT CLAIR AVENUE (OP)-OH	D	69.00	12.00	
26	SAVANNAH AVENUE-OH	D	69.00	22.90	13.09
27	SCHOENBRUNN-OH	D	69.00	12.00	
28	SCHROYER AVENUE-OH	T	69.00	23.00	12.00
29		T	69.00	13.09	
30		T	69.00	4.00	
31		T	69.00		
32	SCIOTO TRAIL (OP)-OH	D	34.50	13.09	
33	SEROCO AVENUE-OH	D	69.00	4.00	
34	SHADYSIDE-OH	D	69.00	13.09	
35	SHARON VALLEY-OH	D	69.00	13.09	
36	SHARP ROAD-OH	T	138.00	69.00	12.00
37		T	69.00		
38	SHAWNEE ROAD-OH	T	138.00	69.50	35.00
39		T	138.00	13.09	
40	SOMERTON-OH	T	138.00	69.00	12.00

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SUBSTATIONS

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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	SOUTH BALTIMORE-OH	T	138.00	69.00	4.00
2	SOUTH BELMONT-OH	D	69.00	13.09	
3	SOUTH BERWICK-OH	T	345.00	68.80	13.09
4	SOUTH CADIZ-OH	T	138.00	69.00	12.00
5		T	69.00	12.00	
6		T	69.00		
7	SOUTH CAMBRIDGE-OH	T	69.00	34.50	
8		T	69.00	34.50	12.00
9		T	69.00		
10	SOUTH CANTON 345KV-OH	T	345.00	137.50	35.00
11	SOUTH CANTON 765KV-OH	T	765.00	345.00	34.50
12	SOUTH COSHOCTON-OH	T	138.00	69.00	12.00
13		T	138.00	34.50	12.00
14		T	138.00	13.09	
15		T	69.00	34.50	12.00
16		T	34.50	12.00	
17	SOUTH CUMBERLAND-OH	T	138.00	69.00	34.50
18		T	138.00	25.00	
19	SOUTH DELPHOS-OH	D	69.00	4.36	
20	SOUTH FINDLAY-OH	D	34.50	13.09	
21		D	34.50		
22	SOUTH GRANVILLE-OH	D	69.00	13.09	
23	SOUTH HICKSVILLE-OH	T	138.00	69.50	13.09
24		T	69.00		
25	SOUTH KENTON-OH	T	138.00	70.00	24.60
26		T	138.00	69.00	
27		T	2.50		
28	SOUTH LANCASTER-OH	T	138.00	69.00	34.50
29		T	138.00	69.00	12.00
30	SOUTH LUCASVILLE-OH	D	138.00	13.09	
31	SOUTH MARTINS FERRY-OH	D	69.00	13.09	
32	SOUTH MILLERSBURG-OH	T	138.00	34.50	7.20
33		T	34.50		
34	SOUTH NEWARK-OH	D	69.00	12.00	
35	SOUTH POINT-OH	T	138.00	69.00	34.50
36		T	138.00	34.50	
37		T	138.00		
38		T	34.50	12.00	
39	SOUTH SIDE LIMA-OH	D	34.50	13.09	
40		D	34.50	4.36	

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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	SOUTH TIFFIN-OH	T	138.00	69.30	6.90
2	SOUTH TORONTO-OH	T	138.00	69.50	13.09
3	SOUTH VAN WERT-OH	D	69.00	13.09	
4		D	69.00	4.36	
5		D	69.00		
6	SOUTHEAST CANTON-OH	T	345.00	138.00	34.50
7	SOUTHEAST LOGAN-OH	D	69.00	12.00	
8	SOUTHWEST LIMA-OH	T	345.00	137.50	13.80
9		T	345.00	137.50	13.12
10		T	138.00		
11	ST RITAS HOSP-OH	D	34.50	4.16	
12	STADIUM PARK-OH	D	69.00	13.09	
13		D	69.00	12.00	
14		D	69.00		
15	STANLEY COURT-OH	T	69.00	23.00	4.00
16		T	69.00	12.00	
17		T	69.00		
18	STERLING-OH	T	138.00	33.00	
19		T	138.00	33.00	11.00
20		T	34.50		
21	STEUBENVILLE-OH	T	138.00	69.00	12.00
22	STONE STREET-OH	D	69.00	13.09	
23		D	69.00	4.36	
24		D	69.00	4.33	
25	STONY HOLLOW-OH	D	69.00	13.09	
26	STRASBURG-OH	D	138.00	36.20	
27	SUGARCREEK TERMINAL-OH	D	138.00	13.09	
28	SUMMERFIELD-OH	T	138.00	69.00	12.00
29	SUMMERHILL-OH	D	69.00	12.00	
30	SUNNYSIDE-OH	T	138.00	23.00	
31		T	138.00	23.00	6.90
32		T	138.00	13.09	
33		T	138.00		
34		T	23.00		
35	SUNSET BOULEVARD-OH	D	69.00	13.09	
36	SWITZER-OH	T	138.00	69.00	12.00
37	TENTH AND OFFNERE STREET-OH	D	34.50	12.00	
38	THAYER ROAD-OH	D	138.00	13.09	
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	THIRD STREET-OH	D	69.00	12.00	
2		D	23.00	4.33	
3		D	23.00	4.00	
4	THORNVILLE-OH	D	69.00	13.09	
5	TIDD 138KV-OH	T	138.00	13.09	
6	TIDD 345KV-OH	T	345.00	138.00	12.00
7		T	345.00	137.50	13.80
8		T	138.00	13.80	
9		T	34.50	4.00	
10	TIDD 69KV-OH	T	138.00	69.00	34.50
11		T	69.00	12.00	
12	TIFFIN CENTER-OH	T	138.00	69.50	13.09
13	TIFFIN TAP-OFF-OH	D	69.00	13.09	
14		D	69.00	4.36	
15	TILTONSVILLE-OH	T	138.00	69.00	12.00
16		T	69.00	12.00	
17		T	69.00		
18	TIMKEN-OH	T	138.00	23.00	
19	TIMKEN MERCY-OH	D	69.00	4.00	
20	TORONTO-OH	D	69.00	13.09	
21	TORREY-OH	T	138.00	69.00	12.00
22		T	138.00	23.00	12.00
23		T	138.00	23.00	11.00
24		T	138.00		
25		T	69.00	12.00	
26		T	69.00		
27		T	23.00	12.00	
28	TWO RIDGES-OH	D	69.00	12.00	
29	UPPER SANDUSKY-OH	D	69.00	13.09	
30		D	69.00		
31	UTICA (OP)-OH	D	69.00	12.00	
32	VAN WERT-OH	D	69.00	13.09	
33		D	69.00	4.36	
34		D	69.00		
35	WAGENHALS-OH	T	138.00	70.50	13.09
36		T	138.00	69.00	23.00
37		T	138.00	23.00	12.00
38		T	138.00		
39	WAKEFIELD-OH	T	138.00	13.09	
40					

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			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	WAYVIEW-OH	T	138.00	69.00	12.00
2		T	138.00	13.09	
3	WEST BELLAIRE-OH	T	345.00	138.00	12.00
4		T	138.00	69.00	12.00
5	WEST CAMBRIDGE-OH	T	138.00	69.00	13.09
6		T	138.00	34.50	
7		T	138.00		
8	WEST CANTON-OH	T	138.00	69.50	13.09
9		T	138.00	36.20	
10		T	138.00	13.09	
11		T	138.00		
12		T	69.00		
13	WEST COSHOCTON-OH	T	138.00	69.00	13.09
14	WEST DOVER-OH	T	138.00	69.50	13.09
15		T	69.00	35.00	
16	WEST END FOSTORIA-OH	T	138.00	69.50	13.09
17		T	138.00		
18		T	69.00	4.36	
19		T	69.00	4.16	
20		T	69.00		
21	WEST GRANVILLE-OH	D	69.00	12.00	
22		D	69.00		
23	WEST HEBRON-OH	T	138.00	69.00	34.50
24		T	34.50	34.50	
25		T	34.50		
26	WEST HICKSVILLE-OH	D	69.00	13.09	
27	WEST LANCASTER-OH	T	138.00	69.00	12.00
28		T	138.00		
29		T	69.00		
30	WEST LIMA-OH	T	138.00	35.00	
31		T	138.00		
32	WEST LOGAN-OH	D	69.00	12.00	
33	WEST LOUISVILLE-OH	D	69.00	12.00	
34		D	69.00		
35	WEST MELROSE-OH	D	34.50	13.09	
36	WEST MILLERSBURG-OH	D	138.00	69.00	34.50
37		D	138.00	34.50	
38	WEST MILLERSPORT-OH	T	345.00	138.00	13.80
39		T	345.00	138.00	12.00
40		T	138.00	69.50	24.15

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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	WEST MOULTON-OH	T	138.00	69.50	13.09
2	WEST MOUNT VERNON-OH	T	138.00	69.00	4.00
3		T	138.00		
4		T	69.00		
5	WEST NEW PHILADELPHIA-OH	T	138.00	69.00	12.00
6		T	138.00	34.50	4.00
7		T	138.00	13.09	
8	WEST TORONTO-OH	D	69.00	12.00	
9	WEST TRINWAY-OH	D	138.00	13.09	
10	WEST VAN WERT-OH	T	69.00	35.00	
11	WEST WOOSTER-OH	D	69.00	12.00	
12		D	69.00		
13	WHIRLPOOL (OP)-OH	D	34.50	13.09	
14	WILLISTON AVENUE-OH	D	69.00	13.09	
15	WINTERSVILLE-OH	D	69.00	12.00	
16	WOODLAWN (OP)-OH	D	138.00	13.09	
17	WOOSTER-OH	T	138.00	69.50	13.09
18		T	138.00	24.14	
19		T	138.00	13.09	
20		T	138.00		
21	ZANESVILLE-OH	T	138.00	69.00	12.00
22		T	138.00	13.09	
23		T	138.00		
24					
25	179 STATIONS UNDER 10 MVA	T/D			
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/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.
129	1					1
			STATCAP	1	18	2
20	1					3
6	1					4
6	1					5
3		1				6
11	1					7
10	1					8
20	1					9
14	2					10
16	2					11
20	1					12
11	1					13
20	1					14
8	1	1				15
11		1				16
20	1					17
42	2					18
13	1					19
20	1					20
20	1					21
9	1					22
9	1					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
129	1					33
20	1					34
			STATCAP	1	13	35
75	1					36
20	1					37
30	1					38
11	1					39
20	1					40

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Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/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.
9	1					1
20	1					2
11	1					3
8	1					4
			STATCAP	1	10	5
84	1					6
448	2					7
40	2					8
11	1					9
130	1					10
9	1					11
75	1					12
10	2					13
11	1					14
11	2					15
22	1					16
9	1					17
9	1					18
			STATCAP	1	14	19
22	1					20
8	1					21
			STATCAP	1	41	22
40	2					23
90	1					24
20	1					25
9	1					26
20	2					27
20	1					28
8	1					29
			STATCAP	1	11	30
6	2					31
22	1					32
1000	2					33
			REACTOR	3	100	34
900	2					35
13	2					36
11	1					37
11	1					38
5	1					39
			STATCAP	1	16	40

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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.
50	1					1
56	1					2
37	1					3
			STATCAP	1	14	4
22	1					5
11	1					6
9	1					7
14	2					8
			STATCAP	1	16	9
50	1					10
			STATCAP	1	29	11
25	1					12
450	1					13
150		1				14
60	1					15
			STATCAP	1	72	16
90	1					17
			STATCAP	1	14	18
11	1					19
			STATCAP	1	14	20
20	1					21
7	2					22
20	1					23
			STATCAP	1	20	24
20	1					25
55	2					26
25	1					27
5	1					28
19	2					29
			STATCAP	1	4	30
11	1					31
20	1					32
11	1					33
84	1					34
25		1				35
20	1					36
			STATCAP	1	22	37
50	1					38
50	1					39
			STATCAP	1		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 2009/Q4

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)	
42	2					1
20	1					2
22	1					3
16	2					4
19	2					5
25	1					6
6	1					7
22	1					8
11	1					9
11	1					10
18	2					11
			STATCAP	1	14	12
75	1					13
9	1					14
			STATCAP	1	14	15
8	3	1				16
5		1				17
7	1					18
			STATCAP	1	14	19
450	1					20
20	1					21
130	1					22
			STATCAP	1	20	23
130	1					24
			STATCAP	1	43	25
6	1					26
			STATCAP	1	13	27
20	1					28
			REACTOR	3	300	29
			STATCAP	2	115	30
130	1					31
1		1				32
20	1					33
25	1					34
22	1					35
20	1					36
6	1					37
75	1					38
35	1					39
10	6	2				40

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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.
13	1					1
5	1					2
			REACTOR	3	300	3
56	1					4
20	1					5
75	1					6
50	1					7
9	1					8
129	1					9
25	1					10
3	1					11
20	1					12
11	1					13
90	1					14
90	1					15
			STATCAP	2	115	16
9	1					17
			STATCAP	1	12	18
11	1					19
8	1					20
15	2					21
			STATCAP	1	18	22
			STATCAP	1	67	23
450	1					24
450	1					25
1500	3					26
			REACTOR	3	300	27
60	2					28
			STATCAP	1	14	29
22	1					30
19	3					31
			STATCAP	1	27	32
25	1					33
22	1					34
9	1					35
5	1					36
15	2					37
22	1					38
11	1					39
			STATCAP	1	14	40

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Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

SUBSTATIONS (Continued)

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11	1					1
			STATCAP	1	10	2
20	1					3
22	1					4
56	1					5
13	1					6
5	1					7
11	1					8
20	1					9
			REACTOR	9	900	10
750		1				11
3000	3					12
20	1					13
14	2					14
33	2					15
25	1					16
22	1					17
11	1					18
75	1					19
33	3					20
			STATCAP	1	53	21
9		2				22
20	1					23
20	1					24
11	1					25
20	1					26
11	1					27
9	2					28
450	1					29
150	1					30
84	1					31
20	1					32
20	1					33
			STATCAP	1	14	34
90	1					35
60	2					36
20	1					37
			STATCAP	1	43	38
			STATCAP	1	10	39
						40

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SUBSTATIONS (Continued)

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40	2					1
			STATCAP	1	14	2
14	2					3
			STATCAP	1	14	4
128	1					5
56	1					6
25		1				7
39	1					8
			STATCAP	1	14	9
20	1					10
			STATCAP	1	13	11
56	1					12
			STATCAP	1	11	13
9	1					14
9	1					15
22	1					16
			STATCAP	1	10	17
39	1					18
22	1					19
			STATCAP	1	18	20
15	1					21
90	1					22
			STATCAP	1	18	23
16	2					24
84	1					25
90	1					26
			STATCAP	1	43	27
			STATCAP	2	31	28
29	2					29
20	1					30
16	2					31
20	1					32
11	1					33
50	1					34
80	2					35
25	1					36
			STATCAP	1	58	37
11		1				38
3	1					39
			STATCAP	1	12	40

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Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

SUBSTATIONS (Continued)

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40	1					1
600	3	1				2
20	1					3
29	2					4
40	1					5
7	1					6
11	1					7
			STATCAP	1	13	8
20	1					9
			STATCAP	1	13	10
50	1					11
			STATCAP	1	5	12
11	1					13
47	2					14
56	1					15
			STATCAP	1	10	16
30	1					17
20	1					18
11	1					19
11	1					20
20	1					21
22	1					22
448	1					23
90		1				24
56	1	1				25
20		1				26
20		1				27
50		1				28
11		1				29
3	1					30
5		1				31
3		1				32
3		1				33
20	1					34
20	1					35
			STATCAP	1	14	36
10	1					37
5	1					38
			STATCAP	1	10	39
21	2					40

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Ohio Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

SUBSTATIONS (Continued)

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			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
11	2					1
9	1					2
			STATCAP	1	11	3
9	1					4
20	1					5
20	1					6
22	1					7
9	1					8
11	1					9
60	1					10
22	1					11
22	1					12
5	1					13
			STATCAP	1	14	14
10	6					15
50	1					16
50	6					17
20	1	1				18
3		1				19
5		2				20
			STATCAP	1	14	21
20	1					22
9	1					23
20	1					24
22	1					25
40	1					26
22	1					27
39	1					28
20	1					29
6	1					30
			STATCAP	1	10	31
22	1					32
16	2					33
11	1					34
25	1					35
84	1					36
			STATCAP	1	19	37
75	1					38
20	1					39
50	1					40

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15	1					1
13	1					2
150	1					3
75	1					4
5	1					5
			STATCAP	1	10	6
50	2					7
39	1					8
			STATCAP	1	14	9
1350	2					10
2750	4	2				11
75	1					12
30	1					13
20	1					14
39	1					15
3		1				16
84	1					17
8		1				18
5	1					19
40	2					20
			STATCAP	1	12	21
20	1					22
75	1					23
			STATCAP	1	18	24
30	1					25
30	2					26
			STATCAP	1		27
130	1					28
60	1					29
11	1					30
22	1					31
25	1					32
			STATCAP	1	6	33
40	2					34
129	1					35
70	4	1				36
			STATCAP	1	67	37
7	2					38
20	1					39
5	1					40

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SUBSTATIONS (Continued)

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50	1					1
60	1					2
22	1					3
5	1					4
			STATCAP	1	10	5
600	1					6
11	1					7
450	1					8
448	1					9
			STATCAP	1	58	10
19	2					11
9	1					12
11	1					13
			STATCAP	1	10	14
37	1					15
20	1					16
			STATCAP	1	13	17
30	3					18
33	3	1				19
			STATCAP	1	14	20
112	1					21
20	1					22
5		1				23
9	3	1				24
20	1					25
30	1					26
22	1					27
84	1					28
20	1					29
42	1					30
30	3					31
20	1					32
			STATCAP	1		33
			STATCAP	1	14	34
22	1					35
15	1					36
22	5	1				37
40	2					38
						39
						40

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SUBSTATIONS (Continued)

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			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
20	1					1
6	3					2
6	3					3
20	1					4
8		1				5
150	1					6
450	1					7
60	1					8
3	2					9
130	1					10
4	1					11
50	1					12
9	1					13
6	1					14
90	1					15
11	1					16
			STATCAP	1	19	17
317	4					18
11	2					19
20	1					20
90	1					21
92	6					22
16		1				23
			STATCAP	1		24
9	1					25
			STATCAP	1	10	26
1		1				27
20	1					28
20	1					29
			STATCAP	1	14	30
11	1					31
22	1					32
6	1					33
			STATCAP	1	16	34
130	1					35
84	1					36
30	1					37
			STATCAP	1	53	38
11	1					39
						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 2009/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)	
130	1					1
22	1					2
400	1					3
115	1					4
90	1					5
30	1					6
			STATCAP	1	43	7
130	1					8
20	1					9
22	1					10
			STATCAP	1	62	11
			STATCAP	1	10	12
56	1					13
90	1					14
30	1					15
75	1					16
			STATCAP	1	58	17
6	1					18
4	1					19
			STATCAP	1	22	20
11	1					21
			STATCAP	1	14	22
129	1					23
25	1					24
			STATCAP	2	5	25
11	1					26
197	2					27
			STATCAP	1	72	28
			STATCAP	1	14	29
250	2					30
			STATCAP	1	58	31
20	1					32
20	2					33
			STATCAP	1	10	34
22	1					35
90	1					36
25	1					37
450	1					38
450	1					39
84		1				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 2009/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.
75	1					1
30	1					2
			STATCAP	1	53	3
			STATCAP	1	13	4
129	1					5
15	1					6
31	2					7
11	1					8
20	1					9
25	1					10
22	1					11
			STATCAP	1	14	12
20	1					13
20	1					14
11	1					15
20	1					16
50	1					17
25	1					18
20	1					19
			STATCAP	1	22	20
130	1					21
25	1					22
			STATCAP	1	58	23
						24
1040	207					25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

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