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
Columbus Southern 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 Columbus Southern 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, OH 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, OH 43215-2373	

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
Columbus Southern 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
Columbus Southern 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	
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	None
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
Columbus Southern 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
Columbus Southern 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 13, 1937

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
Columbus Southern 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
Columbus Southern 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	Conesville Coal Preparation Company	Provides coal washing	100	
2		services for one of the		
3		Company's generating		
4		stations.		
5				
6	NOTE: Colomet, Inc. was merged with Columbus			
7	Southern Power Company as of 5/11/09 per			
8	State of Ohio Certificate #200913300064.			
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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
Columbus Southern 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	Michael G. Morris, Chairman of the Board	Columbus, Ohio
2	and Chief Executive Officer	
3		
4	Brian X. Tierney, Vice Chairman of the Board,	Columbus, Ohio
5	Chief Financial Officer and Vice President	
6		
7	Carl L. English, Vice President	Columbus, Ohio
8		
9	Holly Keller Koeppel, Vice President	Columbus, Ohio
10	and Chief Financial Officer	
11		
12	Robert P. Powers, Vice President	Columbus, Ohio
13		
14	Susan Tomasky, Vice President	Columbus, Ohio
15		
16	Dennis E. Welch, Vice President	Columbus, Ohio
17		
18	Nicholas K. Akins, Vice President	Columbus, Ohio
19		
20	John B. Keane, Secretary	Columbus, Ohio
21		
22	Venita McCellon-Allen, Vice Chairman of the Board	Columbus, Ohio
23	and Vice President	
24		
25	Richard E. Munczinski, Vice President	Columbus, Ohio
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30	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
Columbus Southern 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 April 20, 2009	City of Grandview Heights, Franklin County	Twenty-five (25) year franchise expiring April 20, 2034	None
Renewed on August 2, 2009	Village of Otway, Scioto County, Ohio	Twenty-five (25) year franchise expiring on August 3, 2034	None

2. None

3. None

4. None

5. None

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

   $60 million 3.875% pollution control bonds due 6/1/2014

   $32.245 million 5.8% pollution control bonds due 12/1/2038

7. None

8. None

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

William F. Vineyard resigned as Vice President effective July 1, 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
Columbus Southern 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	5,253,876,362	4,782,461,761
3	Construction Work in Progress (107)	200-201	154,927,997	394,918,010
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		5,408,804,359	5,177,379,771
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	2,045,318,829	1,989,471,318
6	Net Utility Plant (Enter Total of line 4 less 5)		3,363,485,530	3,187,908,453
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)		3,363,485,530	3,187,908,453
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		15,394,662	13,529,593
19	(Less) Accum. Prov. for Depr. and Amort. (122)		3,056,815	3,033,652
20	Investments in Associated Companies (123)		430,000	430,000
21	Investment in Subsidiary Companies (123.1)	224-225	-1,483,512	15,331,882
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	14,539,865	16,303,007
24	Other Investments (124)		12,368,010	12,465,751
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)		23,881,702	28,359,443
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	101,165
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		62,073,912	83,487,189
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		1,095,653	1,062,605
36	Special Deposits (132-134)		31,024,169	45,913,207
37	Working Fund (135)		0	0
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		21,199,052	36,950,938
41	Other Accounts Receivable (143)		16,972,690	30,418,468
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		3,481,442	2,901,859
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		25,172,755	41,337,284
45	Fuel Stock (151)	227	72,012,385	41,177,001
46	Fuel Stock Expenses Undistributed (152)	227	2,146,159	897,910
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	37,341,838	31,710,660
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	41,112,209	36,472,496

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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		14,539,865	16,303,007
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)		20,947,059	21,037,176
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		1,196,442	3,905,184
60	Rents Receivable (172)		828,991	166,573
61	Accrued Utility Revenues (173)		11,845,481	18,358,613
62	Miscellaneous Current and Accrued Assets (174)		1,038,015	0
63	Derivative Instrument Assets (175)		57,240,579	61,513,084
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		23,881,702	28,359,443
65	Derivative Instrument Assets - Hedges (176)		983,993	2,931,514
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	101,165
67	Total Current and Accrued Assets (Lines 34 through 66)		300,254,461	326,187,239
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		6,693,845	8,175,895
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	334,715,592	293,112,866
73	Prelim. Survey and Investigation Charges (Electric) (183)		1,307	1,265
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	109,835,770	98,934,513
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)		9,356,932	10,100,428
82	Accumulated Deferred Income Taxes (190)	234	118,960,211	150,076,821
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		579,563,657	560,401,788
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		4,305,377,560	4,157,984,669

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Columbus Southern 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	41,026,065	41,026,065
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		257,892,418	257,892,418
7	Other Paid-In Capital (208-211)	253	322,772,227	322,614,786
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	786,073,173	664,555,475
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	2,064,800	10,201,991
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)	-49,993,531	-46,850,860
16	Total Proprietary Capital (lines 2 through 15)		1,359,835,152	1,249,439,875
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	0	0
19	(Less) Reaquired Bonds (222)	256-257	0	92,245,000
20	Advances from Associated Companies (223)	256-257	100,000,000	100,000,000
21	Other Long-Term Debt (224)	256-257	1,442,745,000	1,442,745,000
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		6,352,416	6,906,370
24	Total Long-Term Debt (lines 18 through 23)		1,536,392,584	1,443,593,630
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		2,238,573	3,691,076
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		52,893	169,899
29	Accumulated Provision for Pensions and Benefits (228.3)		122,486,763	137,021,977
30	Accumulated Miscellaneous Operating Provisions (228.4)		3,447,229	924,737
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		10,272,145	14,758,182
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		40,700	16,009
34	Asset Retirement Obligations (230)		39,349,106	16,321,341
35	Total Other Noncurrent Liabilities (lines 26 through 34)		177,887,409	172,903,221
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		95,641,617	131,119,957
39	Notes Payable to Associated Companies (233)		28,793,049	84,155,854
40	Accounts Payable to Associated Companies (234)		82,843,693	122,489,126
41	Customer Deposits (235)		27,910,876	30,145,246
42	Taxes Accrued (236)	262-263	167,830,218	187,000,423
43	Interest Accrued (237)		23,521,360	24,517,942
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Columbus Southern 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)		945,526	55,934
48	Miscellaneous Current and Accrued Liabilities (242)		37,019,876	42,026,598
49	Obligations Under Capital Leases-Current (243)		2,124,146	2,661,181
50	Derivative Instrument Liabilities (244)		21,570,096	30,628,418
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		10,272,145	14,758,182
52	Derivative Instrument Liabilities - Hedges (245)		1,794,275	635,712
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		40,700	16,009
54	Total Current and Accrued Liabilities (lines 37 through 53)		479,681,887	640,662,200
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		276,152	278,195
57	Accumulated Deferred Investment Tax Credits (255)	266-267	16,832,959	18,813,083
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	19,710,055	30,284,771
60	Other Regulatory Liabilities (254)	278	29,881,704	14,651,842
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	19,682,408	7,434,999
63	Accum. Deferred Income Taxes-Other Property (282)		534,670,941	455,903,670
64	Accum. Deferred Income Taxes-Other (283)		130,526,309	124,019,183
65	Total Deferred Credits (lines 56 through 64)		751,580,528	651,385,743
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		4,305,377,560	4,157,984,669

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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	2,057,100,425	2,277,642,114		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	1,095,211,853	1,367,342,297		
5	Maintenance Expenses (402)	320-323	126,441,018	109,334,724		
6	Depreciation Expense (403)	336-337	126,946,745	136,122,078		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	2,676,327	453,264		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	11,690,325	11,406,315		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		3,133,858	60,151,713		
13	(Less) Regulatory Credits (407.4)		92,681	21,530,246		
14	Taxes Other Than Income Taxes (408.1)	262-263	175,068,961	167,631,268		
15	Income Taxes - Federal (409.1)	262-263	19,276,023	116,048,112		
16	- Other (409.1)	262-263	618,297	2,954,566		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	315,856,139	165,043,096		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	175,127,692	161,301,660		
19	Investment Tax Credit Adj. - Net (411.4)	266	-1,980,124	-1,953,960		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)			206,872		
22	(Less) Gains from Disposition of Allowances (411.8)		65,741	1,206,204		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		1,358,946	1,378,098		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,701,012,254	1,952,080,333		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		356,088,171	325,561,781		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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
2,057,100,425	2,277,642,114					2
						3
1,095,211,853	1,367,342,297					4
126,441,018	109,334,724					5
126,946,745	136,122,078					6
2,676,327	453,264					7
11,690,325	11,406,315					8
						9
						10
						11
3,133,858	60,151,713					12
92,681	21,530,246					13
175,068,961	167,631,268					14
19,276,023	116,048,112					15
618,297	2,954,566					16
315,856,139	165,043,096					17
175,127,692	161,301,660					18
-1,980,124	-1,953,960					19
						20
	206,872					21
65,741	1,206,204					22
						23
1,358,946	1,378,098					24
1,701,012,254	1,952,080,333					25
356,088,171	325,561,781					26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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)		356,088,171	325,561,781		
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)		4,364	1,210		
34	(Less) Expenses of Nonutility Operations (417.1)					
35	Nonoperating Rental Income (418)		422,929	722,907		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	297,299	669,358		
37	Interest and Dividend Income (419)		801,959	5,164,121		
38	Allowance for Other Funds Used During Construction (419.1)		3,381,744	3,364,031		
39	Miscellaneous Nonoperating Income (421)		10,087,139	7,779,021		
40	Gain on Disposition of Property (421.1)		11,870	414,265		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		15,007,304	18,114,913		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		23,535	149,753		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		4,978,334	10,515,011		
46	Life Insurance (426.2)					
47	Penalties (426.3)		64,326	-211,866		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		726,798	1,235,715		
49	Other Deductions (426.5)		22,257,419	13,732,641		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		28,050,412	25,421,254		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	80,000	315,000		
53	Income Taxes-Federal (409.2)	262-263	-6,234,256	-7,730,036		
54	Income Taxes-Other (409.2)	262-263	288,175	263,477		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	3,146,371	3,607,941		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	12,143,663	7,554,348		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-14,863,373	-11,097,966		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		1,820,265	3,791,625		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		79,206,255	73,458,111		
63	Amort. of Debt Disc. and Expense (428)		1,841,488	1,086,137		
64	Amortization of Loss on Reaquired Debt (428.1)		743,496	757,439		
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)		5,974,022	20,898,929		
68	Other Interest Expense (431)		4,450,067	-1,300,152		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		5,967,995	2,677,247		
70	Net Interest Charges (Total of lines 62 thru 69)		86,247,333	92,223,217		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		271,661,103	237,130,189		
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)		271,661,103	237,130,189		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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		664,555,475	552,162,467
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	Capital Stock Expense	210	-157,440	(157,440)
11	FAS157 Adoption, Net of Tax of $170,244	456		(316,168)
12	EITF 06-10 Adoption, Net of Tax of $589,193	923		(1,094,215)
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)		-157,440	(1,567,823)
16	Balance Transferred from Income (Account 433 less Account 418.1)		271,363,804	236,460,831
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31	Common Stock Dividends		-150,000,000	(122,500,000)
32	Noncash Dividend of Property to Parent		-8,123,156	
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-158,123,156	(122,500,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings	Colomet	8,434,490	
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		786,073,173	664,555,475
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)			
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		786,073,173	664,555,475
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		10,201,991	9,532,633
50	Equity in Earnings for Year (Credit) (Account 418.1)		297,299	669,358
51	(Less) Dividends Received (Debit)			
52	Transfers to Acct 216.0 (Merger of Colomet, Inc.)		-8,434,490	
53	Balance-End of Year (Total lines 49 thru 52)		2,064,800	10,201,991

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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)	271,661,103	237,130,189
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	141,313,397	147,981,657
5	Amortization of Regulatory Debits and Credits (net)	3,041,177	38,621,467
6	Customer Deposits	-2,234,370	-12,950,117
7	Carrying Costs	-7,655,770	-6,550,923
8	Deferred Income Taxes (Net)	131,731,155	-204,971
9	Investment Tax Credit Adjustment (Net)	-1,980,124	-1,953,960
10	Net (Increase) Decrease in Receivables	47,505,234	-15,490,400
11	Net (Increase) Decrease in Inventory	-37,714,812	-3,263,308
12	Net (Increase) Decrease in Allowances Inventory	-4,639,713	962,282
13	Net Increase (Decrease) in Payables and Accrued Expenses	-77,071,632	71,702,561
14	Net (Increase) Decrease in Other Regulatory Assets	-20,076,262	218,156
15	Net Increase (Decrease) in Other Regulatory Liabilities	17,143,899	16,508,005
16	(Less) Allowance for Other Funds Used During Construction	3,381,744	3,364,031
17	(Less) Undistributed Earnings from Subsidiary Companies	297,299	669,358
18	Other (provide details in footnote):	-14,159,782	-58,166,245
19	Deferred Property Taxes	-7,364,449	-2,169,019
20	Over / Under Recovered Fuel, net	-36,028,133	
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	399,791,875	408,341,985
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-305,927,555	-436,376,967
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	-3,381,744	-3,364,031
31	Other (provide details in footnote):		
32	Acquired Assets Subject to Lease-back	-232,002	-807,866
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-302,777,813	-433,820,802
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	823,455	1,576,037
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
Columbus Southern 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	27,659	94,279
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
54	(Increase) Decrease in Other Special Deposits	16,150,341	21,459,947
55	Notes Receivable from Associated Companies		
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-285,776,358	-410,690,539
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	92,245,000	350,000,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65	Deferred Issuance Expenses	-1,084,548	-3,602,807
66	Net Increase in Short-Term Debt (c)		
67	Proceeds from Acquired Assets Subject to Capital Lease	219,884	723,468
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	91,380,336	347,120,661
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)		-204,245,000
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77	Notes Payable to Associated Companies	-55,362,805	-18,353,062
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-150,000,000	-122,500,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-113,982,469	2,022,599
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	33,048	-325,955
87			
88	Cash and Cash Equivalents at Beginning of Period	1,062,605	1,388,560
89			
90	Cash and Cash Equivalents at End of period	1,095,653	1,062,605

FOOTNOTE DATA

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

	2009 Cash Flow Incr / (Decr)	2008 Cash Flow Incr / (Decr)
Utility Plant, Net	(6,251,021)	(7,180,766)
Property and Investments, Net	2,891,813	(44,311)
Margin Deposits	(1,261,303)	(10,124,975)
Mark-to-Market of Risk Management Contracts	(4,785,818)	(10,551,301)
Prepayments	2,774,792	(16,861,053)
Accrued Utility Revenues, Net	6,513,132	(3,543,670)
Miscellaneous Current and Accr Assets	194,821	25,000
Unamortized Debt Expense	2,566,598	755,339
Other Deferred Debits, Net	(4,014,072)	(710,333)
Other Comprehensive Income, Net	1,199,400	(1,180,833)
Unamortized Discount/Premium on Long-Term Debt	553,954	405,944
Accumulated Provisions - Misc	3,226,140	1,689,666
Current and Accrued Liabilities, Net	(6,125,649)	(9,906,199)
Other Deferred Credits, Net	(11,642,569)	(938,753)
Total	(14,159,782)	(58,166,245)

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

	2009 Cash Flow Incr / (Decr)	2008 Cash Flow Incr / (Decr)
Sale of meters to affiliated operating companies	317,209	201,040
Sale of transformers to affiliated operating companies	506,246	600,659
Sale of transformer to Environmental Protection Svcs	-	159,645
Sale of scrap material to JVC Metals LLC	-	100,594
Sale of 8.746 acres - part of Hyatt Station 345kV	-	429,701
Proceeds from acquired assets subject to Operating Lease	-	84,398
Total	823,455	1,576,037

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Columbus Southern 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.

PAGE 122 INTENTIONALLY LEFT BLANK
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
5. Benefit Plans
6. Business Segments
7. Derivatives and Hedging
8. Fair Value Measurements
9. Income Taxes
10. Leases
11. Financing Activities
12. Related Party Transactions
13. Property, Plant and Equipment

GLOSSARY OF TERMS FOR NOTES

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

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP or Parent	American Electric Power Company, Inc.
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.
AEPEP	AEP Energy Partners, Inc., a subsidiary of AEP dedicated to wholesale marketing and trading, asset management and commercial and industrial sales in the deregulated Texas market.
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.
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.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FGD	Flue Gas Desulfurization or Scrubbers.
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.
IRS	Internal Revenue Service.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
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.
MTM	Mark-to-Market.
MW	Megawatt.
MWH	Megawatthour.
NO_X	Nitrogen oxide.
NSR	New Source Review.
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.
PM	Particulate Matter.
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.
SIA	System Integration Agreement.
SO2	Sulfur Dioxide.
SPP	Southwest Power Pool.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
Utility Money Pool	AEP System's Utility Money Pool.
WPCo	Wheeling Power Company, an AEP electric distribution subsidiary.

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

As a public utility, CSPCo engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 749,000 retail customers in central and southern Ohio. As a member of the AEP Power Pool, CSPCo shares 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.

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

Under the SIA, AEPSC allocates physical and financial revenues and expenses from 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 CSPCo's behalf. CSPCo 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. CSPCo shares in coal and emission allowance risk management activities based on its proportion of fossil fuels burned by the AEP System. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and to a lesser extent gas, coal and emission allowances. The electricity, gas, coal and emission allowance contracts include physical transactions, OTC options and financially-settled swaps and exchange-traded futures and options. AEPSC settles the majority of the physical forward contracts by entering into offsetting contracts.

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

CSPCo 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

CSPCo's rates are regulated by the FERC and the PUCO. The FERC also regulates CSPCo'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. CSPCo's wholesale power transactions are generally market-based. Wholesale power transactions are cost-based regulated when CSPCo negotiates and files a cost-based contract with the FERC or the FERC determines that CSPCo has "market power" in the region where the transaction occurs. CSPCo 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 CSPCo's wholesale transmission operations and rates. The FERC claims jurisdiction over retail transmission rates when retail rates are unbundled in connection with restructuring. CSPCo's retail transmission rates are unbundled. CSPCo'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 the 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

CSPCo'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:

- Accounting for subsidiaries on an equity basis.
- The requirement to report deferred tax assets and liabilities separately rather than as a single amount.
- The classification of accrued taxes as a single amount rather than as assets and liabilities.
- The exclusion of current maturities of long-term debt from current liabilities.
- The classification of accrued non-ARO asset removal costs as accumulated depreciation rather than regulatory liabilities.
- The classification of capital lease payments as operating activities instead of financing activities.
- The classification of change in emission allowances held for speculation as investing activities instead of operating activities.
- The classification of gains/losses from disposition of allowances as utility operating expenses rather than as operating revenues.
- The classification of PJM hourly activity for physical transactions as purchases and sales instead of net sales.
- The reporting of acquired generating facilities on a gross basis rather than a net basis.
- The classification of noncurrent tax liabilities related to the accounting guidance for "Uncertainty in Income Taxes" as a current liability rather than a noncurrent liability.
- The classification of 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 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, CSPCo'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," CSPCo 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, CSPCo 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 for:		
Interest (Net of Capitalized Amounts)	$ 94,136	$ 78,692
Income Taxes (Net of Refunds)	46,766	112,897
Noncash Acquisitions Under Capital Leases	892	2,325
At December 31,		
Noncash Construction Expenditures Included in Accounts Payable	31,106	47,438
Revenue Refund Included in Accounts Payable	-	44,178

Special Deposits

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

Inventory

Fossil fuel inventories are generally carried at average cost. Effective January 1, 2009, with the implementation of the FAC in Ohio, CSPCo 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 CSPCo'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, CSPCo 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 CSPCo.

Concentrations of Credit Risk and Significant Customers

CSPCo does not have any significant customers that comprise 10% or more of its Operating Revenues as of December 31, 2009 or 2008.

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

Emission Allowances

CSPCo records emission allowances at cost, including the annual SO_2 and NO_x emission allowance entitlements received at no cost from the Federal EPA. CSPCo 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 sales of emission allowances held speculatively are recorded in Miscellaneous Nonoperating Income and Other Deductions, respectively. The purchases and sales of allowances are reported in the Operating Activities section of the Statements of Cash Flows except speculative allowance transactions, which are reported in Investing Activities.

Property, Plant and Equipment

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

CSPCo has one wholly-owned subsidiary, Conesville Coal Preparation Company (CCPC). CCPC provides coal washing services for one of CSPCo's generating stations. Coal washing services provided by CCPC are priced at cost plus an approved return on investment. Investment in the net assets of the wholly-owned subsidiary is carried at cost plus equity in its undistributed earnings since acquisition. Effective May 2009, Colomet, Inc. merged into CSPCo. Effective September 2008, Simco, Inc. merged into Conesville Coal Preparation Company.

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, Working Fund, accounts receivable and accounts payable approximate fair value because of the short-term maturity of these instruments.

Fair Value Measurements of Assets and Liabilities

The accounting guidance for "Fair Value Measurements and Disclosures" establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. When quoted market prices are not available, pricing may be completed using comparable securities, dealer values, operating data and general market conditions to determine fair value. Valuation models utilize various inputs 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 utilized. Beginning in 2009, CSPCo'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 CSPCo's fuel procurement policies and practices, the fuel cost calculations and FAC deferrals. When a fuel cost disallowance becomes probable, CSPCo adjusts its FAC deferrals and records a provision for estimated refunds to recognize these probable outcomes. Prior to 2009, changes in fuel costs impacted CSPCo'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, CSPCo records them as assets on the balance sheet. CSPCo 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, CSPCo writes off that regulatory asset as a charge against income.

Traditional Electricity Supply and Delivery Activities

CSPCo recognizes revenues from retail and wholesale electricity sales and electricity transmission and distribution delivery services. CSPCo 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, CSPCo'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, CSPCo'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, CSPCo 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 the AEP East companies, PSO and SWEPCo, 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.

CSPCo recognizes revenues and expenses from wholesale marketing and risk management transactions that are not derivatives upon delivery of the commodity. CSPCo 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. CSPCo includes realized gains and losses on wholesale marketing and risk management transactions in Operating Revenues on a net basis on the statements of income. 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.

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). CSPCo 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, CSPCo 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. 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

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

CSPCo 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.

CSPCo accounts for uncertain tax positions in accordance with the accounting guidance for "Income Taxes." CSPCo classifies interest expense or income related to uncertain tax positions as interest expense or income as appropriate and classifies penalties as Penalties.

Excise Taxes

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

Debt

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

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, CSPCo revised book depreciation rates for generating plants consistent with a recently completed depreciation study. In comparing 2009 and 2008, the change in depreciation rates resulted in a net decrease in depreciation expense of $17.8 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

CSPCo 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. CSPCo'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 CSPCo'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 CSPCo to 7% in 2009, 6% in 2010 and 6% in 2011. Some rate components and increases are exempt from these limitations. CSPCo 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 CSPCo to defer any unrecovered FAC costs resulting from the annual caps and to accrue associated carrying charges at CSPCo'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 ESP is 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 CSPCo 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 CSPCo in 2010 related to 2009 earnings and the PUCO issues an order thereon. As a result, CSPCo is unable to determine whether it 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 CSPCo from billing and collecting any ESP rate increases because they assert that the PUCO's statutory jurisdiction over CSPCo's ESP application ended on December 28, 2008. CSPCo 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 have each collected $12 million in pre-construction costs authorized in a June 2006 PUCO order and each 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, CSPCo had recorded a $31 million regulatory asset related to the interim arrangement.

In the ESP proceeding, intervenors requested that CSPCo be required to refund this regulatory asset and requested that the PUCO prevent CSPCo 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 CSPCo 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 CSPCo's retail customers. The PUCO approved the power contract through 2018 with several modifications, including maximum discounts. The PUCO authorized CSPCo 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 CSPCo to credit all Ormet-related POLR charges to reduce the EDR under-recovery regulatory asset amounts that CSPCo would otherwise recover. The new long-term power contract became effective in September 2009, at which point CSPCo began recording a regulatory asset for the unrecovered amounts less Ormet-related POLR revenues. In November 2009, CSPCo 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, CSPCo 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 CSPCo's request. As of December 31, 2009, CSPCo had $10 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 amounts CSPCo will defer for future recovery through the EDR. If CSPCo 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. CSPCo's portion of recognized gross SECA revenues is $38.8 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. CSPCo's portion of the provision is $7.8 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. CSPCo's reserve balance at December 31, 2009 was $5.9 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 CSPCo would be increased on an annual basis through the transmission cost recovery rider (TCRR) mechanism by approximately $10 million. The TCRR includes a true-up mechanism so CSPCo'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 CSPCo would be increased through the TCRR mechanism by approximately $5 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, CSPCo 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:

Regulatory Assets:	December 31, 2009	December 31, 2008	Remaining Recovery Period
	(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)	$ 28,781	$ 27,377	
Line Extension Carrying Costs (a)	26,590	19,933	
Storm Related Costs (a)	17,014	17,300	
Acquisition of Monongahela Power (a)	10,282	8,665	
Regulatory Assets Currently Not Earning a Return			
Peak Demand Reduction/Energy Efficiency (a)	4,071	-	
Total Regulatory Assets Not Yet Being Recovered	86,738	73,275	
Regulatory assets being recovered:			
Regulatory Assets Currently Earning a Return			
Fuel Adjustment Clause	36,982	-	3 to 9 years
Economic Development Rider	10,209	-	1 year
Acquisition of Monongahela Power	2,861	4,935	2 years
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	175,024	187,821	10 to 14 years
Income Taxes Assets	13,674	19,926	26 years
Postemployment Benefits	3,036	3,669	5 years
Total Regulatory Assets Being Recovered	241,786	216,351	
Other	6,192	3,487	various
Total FERC Account 182.3 Regulatory Assets	$ 334,716	$ 293,113	
Unamortized Loss on Reacquired Debt (b)	$ 9,357	$ 10,100	15 years

	December 31, 2009	December 31, 2008	Remaining Refund Period
Regulatory Liabilities:	(in thousands)		
Regulatory liabilities not yet being paid. Payment method and timing to be determined in future proceedings:			
Regulatory Liabilities Currently Not Paying a Return			
Over-recovery of gridSMART℠ Costs	$ 7,477	$ -	
Total Regulatory Liabilities Not Yet Being Paid	7,477	-	
Regulatory liabilities being paid:			
Regulatory Liabilities Currently Paying a Return			
Transmission Cost Recovery Rider	14,811	609	2 years
Regulatory Liabilities Currently Not Paying a Return			
Income Tax Liabilities	3,043	4,856	26 years
Unrealized Gain on Forward Commitments	-	3,487	
Total Regulatory Liabilities Being Paid	17,854	8,952	
Other	4,551	5,700	various
Total FERC Account 254 Regulatory Liabilities	$ 29,882	$ 14,652	
Deferred Investment Tax Credits (b)	$ 16,833	18,813	15 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

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

CSPCo has substantial construction commitments to support its operations and environmental investments. In managing the overall construction program and in the normal course of business, CSPCo contractually commits to third-party construction vendors for certain material purchases and other construction services. CSPCo 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 CSPCo's 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)	$ 226.6	$ 436.4	$ 248.2	$ 441.6	$ 1,352.8
Energy and Capacity Purchase Contracts (b)	3.5	3.1	-	-	6.6
Construction Contracts for Capital Assets (c)	9.7	7.4	13.3	-	30.4
Total	$ 239.8	$ 446.9	$ 261.5	$ 441.6	$ 1,389.8

(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.

Indemnifications and Other Guarantees

Contracts

CSPCo 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.

CSPCo, 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

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

ENVIRONMENTAL CONTINGENCIES

Federal EPA Complaint and Notice of Violation

The Federal EPA, certain special interest groups and a number of states alleged that AEP System companies including CSPCo modified certain units at their coal-fired generating plants in violation of the NSR requirements of the CAA. Cases with similar allegations against CSPCo, Dayton Power and Light Company (DP&L) and Duke Energy Ohio, Inc. were also filed related to their jointly-owned units.

In October 2008, the court approved a consent decree for a settlement reached with the Sierra Club in a case involving CSPCo's share of jointly-owned units at the Stuart Station. The Stuart units, operated by DP&L, are equipped with selective catalytic reduction and FGD controls. Under the terms of the settlement, the joint-owners agreed to certain emission targets related to NO_x, SO_2 and PM. They also agreed to make energy efficiency and renewable energy commitments that are conditioned on receiving PUCO approval for recovery of costs. The joint-owners also agreed to forfeit 5,500 SO_2 allowances and provide $300 thousand to a third party organization to establish a solar water heater rebate program. Another case involving a jointly-owned Beckjord unit had a liability trial. Following the trial, the jury found no liability for claims made against the jointly-owned Beckjord unit. In December 2008, however, the court ordered a new trial in the Beckjord case. Following a second liability trial, the jury again found no liability at the jointly-owned Beckjord unit. In 2009, the defendants and the plaintiffs filed appeals. Beckjord is operated by Duke Energy Ohio, Inc.

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. CSPCo 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. CSPCo 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, CSPCo was named as a Potentially Responsible Party (PRP) for one site by the Federal EPA. There are seven additional sites for which CSPCo has received information requests which could lead to PRP designation. In those instances where CSPCo 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 Conesville plant has been scheduled for the installation of the JBR technology.

The retrofits on the Conesville Plant unit 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

CSPCo 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 CSPCo. 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.

CSPCo 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. CSPCo participates in OPEB plans sponsored by AEP to provide medical and life insurance benefits for retired employees.

CSPCo 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. CSPCo 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. CSPCo 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 the 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

The following table provides CSPCo's net periodic benefit cost (credit) 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)			
$ 2,685	$ (1,426)	$ 9,485	$ 4,948

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 table:

	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

CSPCo 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.

CSPCo's cost for contributions to the retirement savings plans was $4 million and $3.6 million for the years ended December 31, 2009 and 2008, respectively.

UMWA Benefits

CSPCo 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 CSPCo. Benefits are paid from CSPCo's general assets. Contributions and benefits paid were not material in 2009 and 2008.

6. BUSINESS SEGMENTS

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

7. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

CSPCo 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 CSPCo 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 CSPCo, 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 CSPCo, 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 CSPCo, 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 CSPCo, 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	96,828
Coal	Tons	5,615
Natural Gas	MMBtus	9,051
Heating Oil and Gasoline	Gallons	474
Interest Rate	USD	$ 10,658

Cash Flow Hedging Strategies

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

CSPCo's vehicle fleet is exposed to gasoline and diesel fuel price volatility. AEPSC, on behalf of CSPCo, 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." CSPCo does not hedge all fuel price risk.

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," CSPCo 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, CSPCo is required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the December 31, 2009 and 2008 balance sheets, CSPCo 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)			
$ 1,920	$ 16,108	$ 1,229	$ 3,156

The following table represents the gross fair value impact of derivative activity on the balance sheets 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	$ 234,953	$ -	$ -	$ (177,712)	$ 57,241
Long-Term Portion of Derivative Instrument Assets	66,816	-	-	(42,934)	23,882
Derivative Instrument Assets – Hedges	-	1,805	-	(821)	984
Long-Term Portion of Derivative Instrument Assets – Hedges	-	-	-	-	-
Derivative Instrument Liabilities	216,511	-	-	(194,940)	21,571
Long-Term Portion of Derivative Instrument Liabilities	60,048	-	-	(49,776)	10,272
Derivative Instrument Liabilities – Hedges	-	2,615	-	(821)	1,794
Long-Term Portion of Derivative Instrument Liabilities – Hedges	-	41	-	-	41

(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 Recognized
on Risk Management Contracts
For the Year Ended December 31, 2009

Location of Gain	(in thousands)
Operating Revenues	$ 23,088
Regulatory Assets (a)	-
Regulatory Liabilities (a)	15,799
Total Gain on Risk Management Contracts	$ 38,887

(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), CSPCo 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. CSPCo recognizes any hedge ineffectiveness in Net Income immediately during the period of change.

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, CSPCo designated commodity derivatives as cash flow hedges.

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

The following table 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 table 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	$ 1,531	$ -	$ 1,531
Changes in Fair Value Recognized in AOCI	(462)	-	(462)
Amount of (Gain) or Loss Reclassified from AOCI to Income Statement/within Balance Sheet:			
Operating Revenues	(4,088)	-	(4,088)
Operation Expenses	2,667	-	2,667
Depreciation Expense	-	-	-
Interest on Long-term Debt	-	-	-
Utility Plant	(24)	-	(24)
Regulatory Assets (a)	-	-	-
Regulatory Liabilities (a)	-	-	-
Ending Balance in AOCI as of December 31, 2009	$ (376)	$ -	$ (376)

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

CSPCo's amount of income reclassified from AOCI to net income during 2008 was $736 thousand.

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)			
$ 984	$ -	$ (1,794)	$ -	$ (376)	$ -

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)**
$ (349)	$ -	14

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

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

Credit Risk

AEPSC, on behalf of CSPCo, 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 CSPCo, 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 CSPCo, 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), CSPCo 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 $1.1 million. CSPCo would have been required to post $4.3 million of collateral at December 31, 2009 if the credit ratings had declined below investment grade, of which $4 million was attributable to RTO and ISO activities. As of December 31, 2009, CSPCo 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, CSPCo's share of the fair value of derivative liabilities subject to cross-default provisions totaled $78.5 million prior to consideration of contractual netting arrangements. This exposure has been reduced by cash collateral posted of $1.6 million. If a cross-default provision would have been triggered, a settlement of up to $16.8 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)			
$ 1,536,393	$ 1,616,857	$ 1,443,594	$ 1,410,609

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, CSPCo'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)	$ 16,129	$ -	$ -	$ 21	$ 16,150
Derivative Instrument Assets					
Risk Management Contracts (a)	1,188	227,150	6,518	(182,038)	52,818
Dedesignated Risk Management Contracts (b)	-	-	-	4,423	4,423
Total Derivative Instrument Assets	1,188	227,150	6,518	(177,615)	57,241
Derivative Instrument Assets – Hedges (a)	-	1,805	-	(821)	984
Total Assets	$ 17,317	$ 228,955	$ 6,518	$ (178,415)	$ 74,375
Liabilities:					
Derivative Instrument Liabilities					
Risk Management Contracts (a)	$ 1,342	$ 213,330	$ 1,742	$ (196,226)	$ 20,188
DETM Assignment (c)	-	-	-	1,383	1,383
Total Derivative Instrument Liabilities	1,342	213,330	1,742	(194,843)	21,571
Derivative Instrument Liabilities – Hedges (a)	-	2,615	-	(821)	1,794
Total Liabilities	$ 1,342	$ 215,945	$ 1,742	$ (195,664)	$ 23,365

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)	$ 31,129	$ -	$ -	$ 1,171	$ 32,300
Derivative Instrument Assets					
Risk Management Contracts (a)	$ 9,042	366,557	6,724	(328,027)	54,296
Dedesignated Risk Management Contracts (b)	-	-	-	7,218	7,218
Total Derivative Instrument Assets	9,042	366,557	6,724	(320,809)	61,514
Derivative Instrument Assets – Hedges (a)	-	3,725	-	(794)	2,931
Total Assets	$ 40,171	$ 370,282	$ 6,724	$ (320,432)	$ 96,745
Liabilities:					
Derivative Instrument Liabilities					
Risk Management Contracts (a)	$ 10,559	$ 344,860	$ 2,227	$ (329,954)	$ 27,692
DETM Assignment (c)	-	-	-	2,937	2,937
Total Derivative Instrument Liabilities	10,559	344,860	2,227	(327,017)	30,629
Derivative Instrument Liabilities – Hedges (a)	-	1,429	-	(794)	635
Total Liabilities	$ 10,559	$ 346,289	$ 2,227	$ (327,811)	$ 31,264

(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.

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,	$ 4,497	$ (263)
Realized (Gain) Loss Included in Net Income (or Changes in Net Assets) (a) (b)	(743)	86
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	4,234	1,724
Purchases, Issuances and Settlements (c)	(2,940)	-
Transfers in and/or out of Level 3 (d)	(272)	(537)
Changes in Fair Value Allocated to Regulated Jurisdictions (e)	-	3,487
Balance as of December 31,	$ 4,776	$ 4,497

(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	$ 19,894	$ 119,003
Deferred	140,728	3,741
Deferred Investment Tax Credits	(1,980)	(1,954)
Total	158,642	120,790
Charged (Credited) to Nonoperating Income, Net:		
Current	(5,946)	(7,467)
Deferred	(8,997)	(3,946)
Deferred Investment Tax Credits	-	-
Total	(14,943)	(11,413)
Total Income Taxes	$ 143,699	$ 109,377

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	$ 271,661	$ 237,130
Income Taxes	143,699	109,377
Pretax Income	$ 415,360	$ 346,507
Income Tax on Pretax Income at Statutory Rate (35%)	$ 145,376	$ 121,277
Increase (Decrease) in Income Tax resulting from the following items:		
Depreciation	3,776	3,659
Investment Tax Credits, Net	(1,980)	(1,954)
State and Local Income Taxes	2,894	947
Parent Company Loss Benefit	(2,973)	(6,634)
Other	(3,394)	(7,918)
Total Income Taxes	$ 143,699	$ 109,377
Effective Income Tax Rate	34.6%	31.6%

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

	December 31, 2009	2008
	(in thousands)	
Deferred Tax Assets	$ 118,960	$ 150,077
Deferred Tax Liabilities	(684,880)	(587,358)
Net Deferred Tax Liabilities	$ (565,920)	$ (437,281)
Property Related Temporary Differences	$ (496,890)	$ (410,151)
Amounts Due from Customers for Future Federal Income Taxes	(3,182)	(4,789)
Deferred State Income Taxes	(9,223)	(5,522)
Deferred Income Taxes on Other Comprehensive Loss	24,590	25,227
Accrued Pensions	8,167	10,257
Regulatory Assets	(74,298)	(75,520)
All Other, Net	(15,084)	23,217
Net Deferred Tax Liabilities	$ (565,920)	$ (437,281)

CSPCo 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.

CSPCo and other AEP subsidiaries are no longer subject to U.S. federal examination for years before 2001. CSPCo 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, CSPCo 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.

CSPCo, along with other AEP subsidiaries, files income tax returns in various state and local jurisdictions. These taxing authorities routinely examine the tax returns and CSPCo 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, CSPCo is no longer subject to state or local income tax examinations by tax authorities for years before 2000.

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

	Years Ended December 31,	
	2009	**2008**
	(in thousands)	
Interest Expense	$ 1,091	$ 153
Interest Income	-	3,304
Reversal of Prior Period Interest Expense	200	3,411

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

	December 31,	
	2009	**2008**
	(in thousands)	
Accrual for Receipt of Interest	$ 2,281	$ 3,905
Accrual for Payment of Interest and Penalties	206	920

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

	2009	2008
	(in thousands)	
Balance at January 1,	$ 21,179	$ 19,753
Increase - Tax Positions Taken During a Prior Period	6,068	1,198
Decrease - Tax Positions Taken During a Prior Period	(9,994)	(1,207)
Increase - Tax Positions Taken During the Current Year	-	1,575
Decrease - Tax Positions Taken During the Current Year	(195)	(311)
Increase - Settlements with Taxing Authorities	-	171
Decrease - Settlements with Taxing Authorities	-	-
Decrease - Lapse of the Applicable Statute of Limitations	(320)	-
Balance at December 31,	$ 16,738	$ 21,179

The total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate was $9.7 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 CSPCo'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 CSPCo a material favorable cash flow benefit of $16.8 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 CSPCo.

State Tax Legislation

Under Ohio House Bill 66, enacted in 2005, CSPCo reversed deferred state income tax liabilities that were not expected to reverse during a phase-out. The PUCO ordered CSPCo to amortize $15 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 10 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	Years Ended December 31, 2008
	(in thousands)	
Net Lease Expense on Operating Leases	$ 45,114	$ 42,318
Amortization of Capital Leases	2,572	3,190
Interest on Capital Leases	135	460
Total Lease Rental Costs	$ 47,821	$ 45,968

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

	December 31, 2009	December 31, 2008
	(in thousands)	
Property, Plant and Equipment Under Capital Leases		
Production	$ 6,989	$ 7,104
Other Property, Plant and Equipment	7,754	9,417
Total Property, Plant and Equipment	14,743	16,521
Accumulated Amortization	10,409	10,187
Net Property, Plant and Equipment Under Capital Leases	$ 4,334	$ 6,334
Obligations Under Capital Leases		
Noncurrent	$ 2,239	$ 3,691
Current	2,124	2,661
Total Obligations Under Capital Leases	$ 4,363	$ 6,352

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

	Capital Leases	Noncancelable Operating Leases
	(in thousands)	
2010	$ 2,150	$ 42,439
2011	1,269	46,341
2012	256	36,501
2013	221	34,583
2014	187	32,616
Later Years	601	89,600
Total Future Minimum Lease Payments	4,684	$ 282,080
Less Estimated Interest Element	321	
Estimated Present Value of Future Minimum Lease Payments	$ 4,363	

Master Lease Agreements

CSPCo 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, CSPCo 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 $10.1 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, CSPCo 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, CSPCo 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 $1.7 million. Historically, at the end of the lease term the fair market value has been in excess of the unamortized balance.

11. FINANCING ACTIVITIES

Preferred Stock

As of December 31, 2009, CSPCo had 2,500,000 authorized shares of $100 par value preferred stock and 7,000,000 authorized shares of $25 par value preferred stock. At December 31, 2009 and 2008, there were no outstanding shares.

Long-term Debt

There are certain limitations on establishing liens against the CSPCo'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	2010-2035	5.81%	4.40%-6.60%	4.40%-6.60%	$ 1,250,000	$ 1,250,000
Pollution Control Bonds (a)	2012-2038 (b)	4.78%	3.875%-5.80%	4.85%-5.10%	192,745	100,500
Notes Payable – Affiliated	2010	4.64%	4.64%	4.64%	100,000	100,000
Unamortized Discount					(6,352)	(6,906)
Total Long-term Debt					$ 1,536,393	$ 1,443,594

(a) Under the terms of the pollution control bonds, CSPCo 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	$ 250,000
2011	-
2012	44,500
2013	306,000
2014	60,000
After 2014	882,245
Total Principal Amount	1,542,745
Unamortized Discount	(6,352)
Total	$ 1,536,393

In March 2010, CSPCo issued $150 million of Floating Rate Notes due in 2012.

Dividend Restrictions

CSPCo 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 CSPCo 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, CSPCo understands "capital account" to mean the par value of the common stock multiplied by the number of shares outstanding. Additionally, the Federal Power Act creates a reserve on earnings attributable to hydroelectric generating plants.

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 $132 million of the retained earnings of CSPCo 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 borrowings from the Utility Money Pool as of December 31, 2009 and 2008 is included in Notes Payable to Associated Companies on the balance sheets. CSPCo'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	Borrowings from Utility Money Pool as of December 31,	Authorized Short-Term Borrowing Limit
	(in thousands)					
2009	$ 212,608	$ 3,113	$ 108,907	$ 3,113	$ 28,793	$ 350,000
2008	246,822	141,346	134,846	42,429	84,156	350,000

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%	0.15%	0.58%	0.58%	1.04%	0.58%
2008	5.37%	2.28%	5.47%	2.28%	3.59%	3.27%

Interest expense related to the Utility Money Pool is included in Interest Charges. CSPCo incurred interest expense for amounts borrowed from the Utility Money Pool of $1.2 million and $2.4 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. CSPCo earned interest income for amounts advanced to the Utility Money Pool of $329 and $710 thousand for the years ended December 31, 2009 and 2008, respectively.

Credit Facilities

CSPCo 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.

CSPCo 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 CSPCo. Under the factoring arrangement, CSPCo 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 CSPCo's receivables and administrative costs.

The amount of factored accounts receivable and accrued unbilled revenues was $169.1 million and $144.9 million at December 31, 2009 and 2008, respectively.

The fees paid to AEP Credit for factoring customer accounts receivable were $11.2 million and $12.7 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

CSPCo, along with APCo, I&M, KPCo and OPCo, 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, CSPCo, along with APCo, I&M, KPCo and OPCo, 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	$ 57,373	$ 101,743
Direct Sales to West Affiliates	1,169	9,849
Natural Gas Contracts with AEPES	(4,866)	(1,203)
Other	13,537	12,560

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	$ 316,490	$ 334,983
Direct Purchases from East Affiliates	75,469	77,296
Direct Purchases from West Affiliates	802	1,239

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.

CSPCo, along with APCo, I&M, KPCo and OPCo, 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.

CSPCo's net charges allocated under the TA during the years ended December 31, 2009 and 2008 were $51.3 million and $55.3 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.

Transfer of Property

In May 2009, CSPCo transferred a parking garage to AEP through a dividend. AEP then transferred the property to AEPSC through a capital contribution. The transfers were effective May 2009 and were recorded at net book value of $8 million.

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. Beginning in 2007, PSO and SWEPCo were allocated a portion of the DETM assignment based on the SIA methodology of sharing trading and marketing margins between the AEP East companies, PSO and SWEPCo. 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. CSPCo's risk management liabilities related to DETM at December 31, 2009 and 2008 were $1.4 million and $2.9 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. CSPCo's purchases of gas managed by AEPES were $229 thousand and $707 thousand for the years ended December 31, 2009 and 2008, respectively. These purchases are reflected in Operation Expenses.

Unit Power Agreements (UPA)

In March 2007, CSPCo, along with AEGCo, entered into a 10-year UPA for the entire output from the Lawrenceburg Generating Station effective with AEGCo's purchase of the plant in May 2007. The UPA has an option for an additional 2-year period. I&M operates the plant under an agreement with AEGCo. Under the UPA, CSPCo pays AEGCo for the capacity, depreciation, fuel, operation and maintenance and tax expenses. These payments are due regardless of whether the plant is operating. The fuel and operation and maintenance payments are based on actual costs incurred. All expenses are trued up periodically.

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. CSPCo recorded these billings as capital or maintenance expense depending on the nature of the services received. These billings are recoverable from customers. CSPCo was billed $1.3 million and $682 thousand 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 for the years ended December 31, 2009 and 2008 were $783 thousand and $90 thousand, respectively.

Affiliate Railcar Agreement

CSPCo 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. CSPCo records these costs in Fuel Stock on its Comparative Balance Sheet and such costs are recoverable from customers. Under the agreement, CSPCo paid $11 thousand and $1 thousand for the years ended December 31, 2009 and 2008, respectively.

Purchased Power from OVEC

The amounts of power purchased by CSPCo 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 $29.3 million and $26.9 million, respectively. The amounts shown above are recoverable from customers and are included in Operation Expenses.

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. CSPCo's amount recorded for the year ended December 31, 2008 was $10.4 million.

Sales and Purchases of Property

CSPCo 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 CSPCo	$ -	$ 858
CSPCo to PSO	-	180
OPCo to CSPCo	344	-

In addition, CSPCo 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	I&M	OPCo	PSO	SWEPCo	WPCo	Total
Sales	(in thousands)						
2009	$ 30	$ 26	$ 664	$ 93	$ 6	$ 3	$ 822
2008	18	15	580	2	-	5	620

	APCo	I&M	KPCo	OPCo	PSO	SWEPCo	WPCo	Total
Purchases	(in thousands)							
2009	$ 32	$ 88	$ 23	$ 2,748	$ 42	$ 27	$ 6	$ 2,966
2008	27	86	11	3,446	98	-	6	3,674

The amounts above are recorded in Utility Plant at cost.

Global Borrowing Notes

AEP issued long-term debt, portions of which were loaned to CSPCo. AEP pays the interest on the global notes, but CSPCo 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

CSPCo and its affiliates 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. CSPCo's total billings from AEPSC were $124 million and $136 million for the years ended December 31, 2009 and 2008, respectively.

13. PROPERTY, PLANT AND EQUIPMENT

Depreciation

CSPCo 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	Other Generation	Steam	Transmission	Distribution	General
			(in percentages)		
2009	2.3	1.9	2.2	3.4	10.2
2008	2.2	2.8	2.3	3.5	9.0

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)

CSPCo 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. CSPCo 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 CSPCo plans to use its facilities indefinitely. The retirement obligation would only be recognized if and when CSPCo 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	$ 16,321	$ 1,387	$ -	$ (2,853)	$ 24,494	$ 39,349
2008	20,587	1,404	-	(2,731)	(2,939)	16,321

Jointly-owned Electric Facilities

CSPCo has electric facilities that are jointly-owned with nonaffiliated companies. Each of the participating companies is obligated to pay its share of the costs of any such jointly-owned facilities in the same proportion as its ownership interest. CSPCo's proportionate share of the operating costs associated with such facilities is included in its statements of operations and the investments and accumulated depreciation are reflected in its balance sheets under Utility Plant as follows:

			Company's Share at December 31, 2009		
Company	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress (e)	Accumulated Depreciation
				(in thousands)	
W.C. Beckjord Generating Station (Unit No. 6) (a)	Coal	12.5%	$ 19,400	$ 120	$ 8,097
Conesville Generating Station (Unit No. 4) (b)	Coal	43.5%	300,646	3,829	44,832
J.M. Stuart Generating Station (c)	Coal	26.0%	498,851	15,442	152,601
Wm. H. Zimmer Generating Station (a)	Coal	25.4%	767,654	4,082	355,457
Transmission	N/A	(d)	69,868	355	46,815
Total			$ 1,656,419	$ 23,828	$ 607,802

			Company's Share at December 31, 2008		
Company	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress (e)	Accumulated Depreciation
				(in thousands)	
W.C. Beckjord Generating Station (Unit No. 6) (a)	Coal	12.5%	$ 18,173	$ 1,780	$ 8,129
Conesville Generating Station (Unit No. 4) (b)	Coal	43.5%	85,587	172,619	51,110
J.M. Stuart Generating Station (c)	Coal	26.0%	477,677	23,782	143,548
Wm. H. Zimmer Generating Station (a)	Coal	25.4%	762,353	3,987	344,259
Transmission	N/A	(d)	69,789	6	45,613
Total			$ 1,413,579	$ 202,174	$ 592,659

(a) Operated by Duke Energy Corporation, a nonaffiliated company.
(b) Operated by CSPCo.
(c) Operated by The Dayton Power & Light Company, a nonaffiliated company.
(d) Varying percentages of ownership.
(e) Primarily relates to environmental upgrades, including the installation of flue gas desulfurization projects at Conesville Generating Station and J. M. Stuart Generating Station.
N/A = Not Applicable

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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				(15,744,140)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				876,164
3	Preceding Quarter/Year to Date Changes in Fair Value				(33,514,313)
4	Total (lines 2 and 3)				(32,638,149)
5	Balance of Account 219 at End of Preceding Quarter/Year				(48,382,289)
6	Balance of Account 219 at Beginning of Current Year				(48,382,289)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				(2,337,017)
8	Current Quarter/Year to Date Changes in Fair Value				1,101,031
9	Total (lines 7 and 8)				(1,235,986)
10	Balance of Account 219 at End of Current Quarter/Year				(49,618,275)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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 [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1		(649,536)	(16,393,676)		
2		736,277	1,612,441		
3		1,444,688	(32,069,625)		
4		2,180,965	(30,457,184)	237,130,189	206,673,005
5		1,531,429	(46,850,860)		
6		1,531,429	(46,850,860)		
7		(1,444,432)	(3,781,449)		
8		(462,253)	638,778		
9		(1,906,685)	(3,142,671)	271,661,103	268,518,432
10		(375,256)	(49,993,531)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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)	4,656,569,021	4,656,569,021
4	Property Under Capital Leases	4,333,703	4,333,703
5	Plant Purchased or Sold		
6	Completed Construction not Classified	580,351,620	580,351,620
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	5,241,254,344	5,241,254,344
9	Leased to Others		
10	Held for Future Use	12,622,018	12,622,018
11	Construction Work in Progress	154,927,997	154,927,997
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	5,408,804,359	5,408,804,359
14	Accum Prov for Depr, Amort, & Depl	2,045,318,829	2,045,318,829
15	Net Utility Plant (13 less 14)	3,363,485,530	3,363,485,530
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	1,997,682,287	1,997,682,287
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	46,772,172	46,772,172
22	Total In Service (18 thru 21)	2,044,454,459	2,044,454,459
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation	864,370	864,370
29	Amortization		
30	Total Held for Future Use (28 & 29)	864,370	864,370
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj		
33	Total Accum Prov (equals 14) (22,26,30,31,32)	2,045,318,829	2,045,318,829

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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
					2
					3
					4
					5
					6
					7
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					30
					31
					32
					33

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

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance	Line
Amortization (d)	Other Reductions (Explain in a footnote) (e)	End of Year (f)	No.
			1
			2
			3
			4
			5
			6
			7
			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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	575	
3	(302) Franchises and Consents	4,700	
4	(303) Miscellaneous Intangible Plant	74,212,243	3,331,103
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	74,217,518	3,331,103
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	7,206,136	
9	(311) Structures and Improvements	242,015,892	12,763,654
10	(312) Boiler Plant Equipment	1,261,969,797	290,996,914
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	301,305,193	9,515,791
13	(315) Accessory Electric Equipment	145,374,421	1,946,230
14	(316) Misc. Power Plant Equipment	38,751,119	1,950,723
15	(317) Asset Retirement Costs for Steam Production	8,312,951	24,494,155
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	2,004,935,509	341,667,467
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		
28	(331) Structures and Improvements		
29	(332) Reservoirs, Dams, and Waterways		
30	(333) Water Wheels, Turbines, and Generators		
31	(334) Accessory Electric Equipment		
32	(335) Misc. Power PLant Equipment		
33	(336) Roads, Railroads, and Bridges		
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)		
36	D. Other Production Plant		
37	(340) Land and Land Rights	3,713,584	
38	(341) Structures and Improvements	13,172,770	937,328
39	(342) Fuel Holders, Products, and Accessories	5,701,664	1,826,632
40	(343) Prime Movers		
41	(344) Generators	322,199,907	1,807,637
42	(345) Accessory Electric Equipment	48,611,162	647,573
43	(346) Misc. Power Plant Equipment	8,172,778	29,492
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	401,571,865	5,248,662
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	2,406,507,374	346,916,129

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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	38,309,401	-237,856
49	(352) Structures and Improvements	48,127,875	235,339
50	(353) Station Equipment	277,295,698	31,073,857
51	(354) Towers and Fixtures	35,049,257	871
52	(355) Poles and Fixtures	71,295,978	10,368,608
53	(356) Overhead Conductors and Devices	72,106,332	6,112,508
54	(357) Underground Conduit	10,497,884	
55	(358) Underground Conductors and Devices	17,795,807	1,330,554
56	(359) Roads and Trails		
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	570,478,232	48,883,881
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	27,988,366	324,929
61	(361) Structures and Improvements	9,781,492	
62	(362) Station Equipment	203,050,912	20,805,611
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	215,869,169	14,020,148
65	(365) Overhead Conductors and Devices	217,599,951	18,739,947
66	(366) Underground Conduit	80,394,469	8,012,273
67	(367) Underground Conductors and Devices	327,969,320	37,857,746
68	(368) Line Transformers	295,188,092	11,276,446
69	(369) Services	129,311,490	5,821,823
70	(370) Meters	79,080,286	26,381,628
71	(371) Installations on Customer Premises	24,280,833	1,179,909
72	(372) Leased Property on Customer Premises	102,689	
73	(373) Street Lighting and Signal Systems	12,250,709	327,602
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,622,867,778	144,748,062
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	3,384,997	-262,543
87	(390) Structures and Improvements	52,743,724	6,287,709
88	(391) Office Furniture and Equipment	5,988,078	36,336
89	(392) Transportation Equipment	2,663,201	-2,622,943
90	(393) Stores Equipment	301,966	
91	(394) Tools, Shop and Garage Equipment	8,709,266	1,643,876
92	(395) Laboratory Equipment	626,872	5,055
93	(396) Power Operated Equipment	3,036	
94	(397) Communication Equipment	14,487,804	1,587,110
95	(398) Miscellaneous Equipment	1,458,066	181,736
96	SUBTOTAL (Enter Total of lines 86 thru 95)	90,367,010	6,856,336
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant	144,371	
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	90,511,381	6,856,336
100	TOTAL (Accounts 101 and 106)	4,764,582,283	550,735,511
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)	4,764,582,283	550,735,511

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
			575		2
			4,700		3
22,027,512			55,515,834		4
22,027,512			55,521,109		5
					6
					7
			7,206,136		8
451,476		205,502	254,533,572		9
22,542,798			1,530,423,913		10
					11
2,995,505			307,825,479		12
219,247		19,609	147,121,013		13
41,196		-16,376	40,644,270		14
			32,807,106		15
26,250,222		208,735	2,320,561,489		16
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					35
					36
			3,713,584		37
		-205,503	13,904,595		38
			7,528,296		39
					40
620,075			323,387,469		41
88,546		-3,307,104	45,863,085		42
113,931			8,088,339		43
					44
822,552		-3,512,607	402,485,368		45
27,072,774		-3,303,872	2,723,046,857		46

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Columbus Southern 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
25,443			38,046,102		48
			48,363,214		49
2,520,801		3,287,496	309,136,250		50
1			35,050,127		51
130,785			81,533,801		52
25,060			78,193,780		53
			10,497,884		54
63,670			19,062,691		55
					56
					57
2,765,760		3,287,496	619,883,849		58
					59
43			28,313,252		60
			9,781,492		61
2,150,663			221,705,860		62
					63
3,116,144			226,773,173		64
5,791,424			230,548,474		65
118,098			88,288,644		66
2,961,293			362,865,773		67
6,095,695			300,368,843		68
1,026,542			134,106,771		69
2,737,081			102,724,833		70
788,524			24,672,218		71
			102,689		72
223,609			12,354,702		73
					74
25,009,116			1,742,606,724		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
5,332			3,117,122		86
56,784			58,974,649		87
957,140			5,067,274		88
			40,258		89
			301,966		90
			10,353,142		91
			631,927		92
			3,036		93
484,470		16,376	15,606,820		94
18,265			1,621,537		95
1,521,991		16,376	95,717,731		96
					97
			144,371		98
1,521,991		16,376	95,862,102		99
78,397,153			5,236,920,641		100
					101
					102
					103
78,397,153			5,236,920,641		104

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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					
3					
4					
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6					
7					
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43					
44					
45					
46					
47	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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				
3	Newbury Project (5674)	12/80		4,991,594
4		12/87		61,220
5				
6	Ohio Operations Center (0528)	6/81		506,771
7				
8	North Galloway - West Jefferson 69KV Right-of-Way	5/98		254,004
9	(5684)			
10				
11	Bolton Substation (0269)	5/05	2019	732,264
12				
13	Berrywood Substation (0276)	3/06		252,572
14				
15	Galena Substation (0300)	5/08	2011	2,284,067
16				
17	Lincoln - Berrywood 69KV (C977)	6/09	2013	256,991
18				
19	Items under $250,000			1,707,763
20				
21	Other Property:			
22				
23				
24				
25	Items under $250,000			874,775
26				
27				
28				
29				
30				
31				
32				
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41				
42				
43				
44				
45				
46				
47	Total			12,622,018

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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				
3	South Worthington 138/34.5kV Substation (0383)	8/09	2011	699,997
4				
5				
6				
7				
8				
9				
10				
11				
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15				
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18				
19				
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21	Other Property:			
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41				
42				
43				
44				
45				
46				
47	Total			12,622,018

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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	CSP/Sectionalizing Program	171,458
3	CV4 FGD Landfill	8,167,525
4	CSP R/W Widening Prog	994,311
5	EIMS: GHG & TITLE V MODEL	587,522
6	CV U4 FGD Phase 2B	-998,054
7	Rome-Hilliard line Relocation	1,760,270
8	Ross-Highland Rebuild	5,373,315
9	Marquis Station	7,178,567
10	Waverly/Lick Stations	675,353
11	Waverly-Lick 138 kV Line	389,772
12	Marquis Station	1,283,523
13	Marquis Station	793,979
14	Circuit Breaker Rehab Program-CSP	132,822
15	Circuit Breaker Rehab Program-CSP	367,408
16	CSP Relay Rehab Projects	444,100
17	CSP Line Rehab Program	5,058,877
18	OSU-Roberts Ohio Line Power Siting	745,498
19	Roberts-Add 345 & 138 kV Line Pos	7,567,622
20	OSU Station - Add 138 kV Line Pos.	442,068
21	Hess&Vine Stations-Add Reactor+Prot	530,170
22	CSP Hg Monitoring Project	4,353,326
23	TS/CSP/Cor 345 Remot End Relay	642,003
24	TS/CSP/Kirk 345kV Remote Relay	542,321
25	TS/CSP/Jug St Rd Station	8,113,427
26	CSP/Town St Reconstruction	1,855,181
27	TS/CSP/Lincoln - Berrywood	2,119,232
28	ACCESS CONTROL CSP-G	241,340
29	TS/CSP/OH LICK WAVERLY STAT	111,389
30	TS/CSP/OH LICK WAVERLY STAT	148,938
31	DS/CSP/VIGO- REBLD PER SYS 1ST	1,473,113
32	TL/CSP/Tap to Jug Station Rd	597,996
33	TS/CSP/Purchase-Rebuild Maj Eq	1,234,037
34	DS/CSP/Purchase-Rebuild Eq	2,998,063
35	DS/CSP/Metering Upgrade	103,398
36	D/CSP/Brkr Task Force Upgrade	1,557,246
37	TL/CSP/Rebuild existing 1.66 m	106,850
38	TS/CSP/Etna 40K Extension	175,299
39	T/CSP/Security Application Enh	7,391,305
40	CSP/Cutout-Arrester	119,594
41	TL/CSP/Wilson-Briggsdale 39Kv	728,756
42	Mound St Indoor Vehicle Storag	669,531
43	TOTAL	154,927,997

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Columbus Southern 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	CV0 CENTRAL HYDROGEN SYS REPL	696,645
2	MARIETTA SC - FURNITURE	252,152
3	CV U4-6 Waste Transport System	756,417
4	GRANDVIEW PAVING PROJECT	126,824
5	TS/CSP/CCD Replace Zimmer 345k	268,415
6	CV CI U4 HP TURBINE UPGRADE	1,274,526
7	CV56 FGD LANDFILL VERT EXP F	411,446
8	CV6 FGD IMPROVEMNETS	1,521,319
9	CV Mecury Mit Advanced E&D	1,136,919
10	CSP/Svc to River South Comm	255,044
11	CSP/Civic Center Dr Relocate	1,004,278
12	CSP/Town & Rich St Relocation	869,628
13	CSP/UG Primary Cable Rehab	386,257
14	Ohio Comp UG Ntwk Civil	721,557
15	CSP/Vine St Duct & Manhole Add	236,131
16	CSP/Cols S&W Ntwk Xfmer	149,145
17	CSP/Cols North Ntwk Rebuild	1,470,844
18	CSP/Hyatt 50 MVA 138/13kV - D	2,437,505
19	CSP/Blendon Sta UG Line	282,572
20	CSP/Blacklick Sta - UG Line	1,383,220
21	CSP/PenWest Development	1,216,880
22	CSP Vine Ntwk Improve	350,878
23	CSP/ Blacklick Sta Wk 34kV Ckt	277,783
24	CSP/Blacklick Sta UG Line	243,461
25	CSP/Brookside Station D FERC	1,970,328
26	CSP/Brookside Sta T FERC	715,287
27	CSP/Bethel Sta Remote Relay	523,681
28	CSP/Sawmill Sta Remote Relay	441,836
29	CSP/Jug St Sta OH Line	303,694
30	CSP/Jug St Sta D FERC	2,008,516
31	CSP/Jug St Sta T FERC	407,800
32	CSP Mifflin Station	586,140
33	CSP/Mifflin Station T FERC	138,404
34	CSP/Morse Rd Station	647,443
35	CSP/Marion Sta Dist OH Line	287,100
36	CSP/Marion Station	310,154
37	CSP/Marion Sta Distr UG Line	158,864
38	CSP/Shannon Sta Distr UG Line	231,272
39	CSP/White Rd Station	154,358
40	CSP/Gahanna Sta AdaptiVolt	598,232
41	CSP/Gahanna D Line AdaptiVolt	248,813
42	CSP/Blacklick Station IVVC	145,703
43	TOTAL	154,927,997

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Columbus Southern 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	CSP/E Broad St Station IVVC	367,644
2	CSP/Gahanna Sta GE CVVC	223,462
3	CSP/Gahanna D Line IVVC	509,184
4	CSP/Karl Rd Station IVVC	201,864
5	Ds-Csp-Ai-Pole Reinforcement	144,012
6	Ds-Csp-Ai Recloser Replacement	119,679
7	Indus Upgrade for CSP Trans	203,161
8	Indus Upgrade for CSP Gen	875,991
9	Indus Upgrade for CSP Distr	650,359
10	CUST OPS gridSMART-CAP-D	2,084,750
11	Conesville U6 Main Stm. Link Piping	349,113
12	U4 Main Power Transformer	785,971
13	Stuart Elk Run Design/Eng	675,738
14	Replace Auxiliary Boiler	1,387,730
15	Replace Water Walls U3	361,638
16	U1 Generator Field Rewind	113,941
17	U1 Replace Pendant Reheater	1,035,889
18	U3 SCR Catalyst Replacement	280,844
19	SCR Upgrade Engineering	1,137,116
20	Stuart FGD Improvements	1,869,636
21	Stuart Arc Flash Project	677,786
22	CV5 FGD IMPROVEMENTS	205,454
23	WS-CI-CSPCo-G PPB	4,686,549
24	WS-CI-CCDCo-G PPB	8,684,046
25	ET-CI-CSPCo-T SYS IMP	1,561,941
26	ED-CI-CSPCo-D AST IMP	5,118,620
27	ED-CI-CSPCo-D CUST MTR	704,561
28	ED-CI-CSPCo-D CUST SERV	1,468,332
29	ED-CI-CSPCo-D LN TRNSF	361,194
30	EC-CI-CSPCo-D TELECOM	255,799
31	WS-CSPCo-G	5,267,145
32	ET-CSPCo-T	274,953
33	ED-CSPCo-D	954,981
34	SS-CI-CSPCo-G Software	280,634
35	SS-CI-CSPCo-D Software	406,270
36	ET-CI-CSP-T Drvn D Asset Imp	686,268
37	CSP-D Service Restoration Blkt	324,644
38	CSP-D Small Cap Adds Blkt	880,337
39	CSP-D Third Party Work Blkt	630,252
40	Zimmer Sidewall Mix Section	502,633
41	Sequence 3 Landfill	1,521,017
42	Repl FGD Abs Inlet Exp joints	318,548
43	TOTAL	154,927,997

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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	Replace HP LP and FP Turb Ctrl	181,869
2	Repl Horizontal Reheater	266,794
3	Repl SCR 1st Layer Catalyst	346,918
4	Other Minor Projects Under $100,000	426,808
5	TOTAL STATE OF OHIO: $154,927,997	
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42		
43	TOTAL	154,927,997

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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	1,932,342,055	1,931,452,771	889,284	
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	124,339,286	124,339,286		
4	(403.1) Depreciation Expense for Asset Retirement Costs	2,676,327	2,676,327		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing				
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):	223,299	219,352	3,947	
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	127,238,912	127,234,965	3,947	
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	56,351,690	56,351,690		
13	Cost of Removal	16,984,020	16,984,020		
14	Salvage (Credit)	6,147,917	6,147,917		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	67,187,793	67,187,793		
16	Other Debit or Cr. Items (Describe, details in footnote):	6,153,483	6,182,344	-28,861	
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	1,998,546,657	1,997,682,287	864,370	
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	892,641,420	892,641,420		
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production	119,704,429	119,704,429		
25	Transmission	234,283,632	234,236,730	46,902	
26	Distribution	711,733,120	710,915,652	817,468	
27	Regional Transmission and Market Operation				
28	General	40,184,056	40,184,056		
29	TOTAL (Enter Total of lines 20 thru 28)	1,998,546,657	1,997,682,287	864,370	

FOOTNOTE DATA

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

Depreciation on Monongahela incremental costs	$188,391
Depreciation for Conesville Plant Conveyor - account 151	27,305
Reclass asbestos accretion and depreciation to account 1080013	3,656
TOTAL	$219,352

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

Depreciation expense on account 105 classified to account 421	$3,947

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

RWIP transferred to In-Service	$6,183,376
Account 1080013 ARO removal	- 31,846
Reserve transferred between accounts	30,814
TOTAL	$6,182,344

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

Reserve transferred between accounts	-$28,861

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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	COLOMET, INC.			
2	Common Stock			1,500,000
3	Premium on Capital Stock			30,000
4	Equity - Undistributed Earnings			8,207,192
5	Investment Advances			2,822,302
6	Subtotal			12,559,494
7				
8	NOTE: Colomet, Inc. was merged with Columbus			
9	Southern Power Company as of 5/11/2009 per			
10	State of Ohio Certificate #200913300064			
11				
12	CONESVILLE COAL PREPARATION COMPANY			
13	Common Stock			109,000
14	Premium on Capital Stock			668,589
15	Equity - Undistributed Earnings			1,994,799
16	Investment in Subsidiary AOCI			
17	Subtotal			2,772,388
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
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31				
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41				
42	Total Cost of Account 123.1 $ 777,589		TOTAL	15,331,882

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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
	-1,500,000			2
	-30,000			3
227,298	-8,434,490			4
	-2,822,302			5
227,298	-12,786,792			6
				7
				8
				9
				10
				11
				12
		109,000		13
		668,589		14
70,001		2,064,800		15
		-4,325,901		16
70,001		-1,483,512		17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
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				36
				37
				38
				39
				40
				41
297,299	-12,786,792	-1,483,512		42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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)	41,177,001	72,012,385	Electric
2	Fuel Stock Expenses Undistributed (Account 152)	897,910	2,146,159	Electric
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	26,462,482	24,899,970	Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	3,234,052	8,010,440	Electric
8	Transmission Plant (Estimated)	206,487	311,327	Electric
9	Distribution Plant (Estimated)	1,633,306	3,596,663	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	174,333	523,438	Electric
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	31,710,660	37,341,838	
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)	73,785,571	111,500,382	

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
Columbus Southern 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	151,636.00	17,485,593	74,605.00	1,763,142
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	5.00			
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	Ohio Power Company	32,707.00	15,393,223		
10	Appalachian Power Company	1,994.00	938,456		
11					
12					
13					
14					
15	Total	34,701.00	16,331,679		
16					
17	Relinquished During Year:				
18	Charges to Account 509	44,456.00	5,293,516		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22	Aep System Pool	25,922.00	5,218,300		
23	US EPA	350.00	40,391		
24					
25					
26					
27					
28	Total	26,272.00	5,258,691		
29	Balance-End of Year	115,614.00	23,265,065	74,605.00	1,763,142
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year	855.00		854.00	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	855.00			
40	Balance-End of Year			854.00	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)		60,543		
45	Gains		60,543		
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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.
81,528.00	2,918,269	66,583.00	2,909,101	1,581,859.00	8,712,495	1,956,211.00	33,788,600	1
								2
								3
				59,942.00		59,947.00		4
								5
								6
								7
								8
						32,707.00	15,393,223	9
						1,994.00	938,456	10
								11
								12
								13
								14
						34,701.00	16,331,679	15
								16
								17
						44,456.00	5,293,516	18
								19
								20
								21
						25,922.00	5,218,300	22
						350.00	40,391	23
								24
								25
								26
								27
						26,272.00	5,258,691	28
81,528.00	2,918,269	66,583.00	2,909,101	1,641,801.00	8,712,495	1,980,131.00	39,568,072	29
								30
								31
								32
								33
								34
								35
854.00		856.00		37,158.00		40,577.00		36
				1,712.00		1,712.00		37
								38
				857.00		1,712.00		39
854.00		856.00		38,013.00		40,577.00		40
								41
								42
								43
					5,198		65,741	44
					5,198		65,741	45
								46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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						
33						
34						
35						
36						
37						
38						
39						
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
Columbus Southern 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	St Clairsville-System Study Agrmnt	1,126	186		
3	Beach City-69kV Chestnut Del Pt	4,398	186		
4	Shannon - Pickerington Rd Del Pt	174	186		
5	Lebanon - 138kV Delivery Point	21,378	186		
6	Dover - System Impact Study	9,390	186		
7	PJM - IPP R44 Rockport - Impact	58,971	186	43,941	186
8	Sporn-Waterford 345kV	46,104	186	15,000	186
9	Buckeye Pwr-Blacklick 138kV Del	103	186		
10	PJM-CV #5 345kV Feasibility	15	186	15	186
11	PJM-CV #6 345kV Feasibility	15	186	15	186
12	PJM-CV #5 345kV Impact Study	31	186	31	186
13	PJM-CV #6 345kV Impact Study	31	186	31	186
14	PJM-Highland 69kV Feasibility	242	186	242	186
15	Westerville - 138kV System Impact	4,336	186	2,000	186
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	Conesville #5 Feasibility Study	10,230	500	3,084	500
23	Conesville #6 Feasibility Study	9,918	500	3,593	500
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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 (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	SFAS 112 - Postemployment Benefits	3,668,528	239,513	228.3	871,727	3,036,314
2						
3	DSM Program Costs		4,070,698			4,070,698
4	Ohio ESP - Case No. 08-917-EL-SSO					
5						
6	Deferred Storm Expense	17,300,000		593	285,647	17,014,353
7	Hurricane Ike - Ohio Wind Storm 9/14/08					
8	-Case No. 08-1301-EL-AAM					
9						
10	Deregulation Consumer Education	938,595				938,595
11						
12	Deregulation Transition Filing	902				902
13						
14	Deregulation Implementation	22,832,730	629,982	Various	52,216	23,410,496
15						
16	Carrying Charges - Deferred Ohio Deregulation	12,707,422	3,271,503			15,978,925
17						
18	Extension of Local Facilities	42,204,367	15,395,495	421,456	1,300,201	56,299,661
19						
20	Reg Asset - Rate Case Expenses	135,489				135,489
21						
22	Deferred Equity Carrying Charges	(9,586,753)	928,040	421	4,245,976	-12,904,689
23	(Amort. periods from 01/2005 up to 12/2019)					
24						
25	BridgeCo TO Funding	609,153		407.3	33,504	575,649
26	Per FERC Docket No AC04-101-000					
27	(Amort. period from 01/2005 to 12/2019)					
28						
29	PJM Integration Payments	1,195,128		407.3	162,415	1,032,713
30	Per FERC Docket No EL05-74-000					
31	(Amort. period from 01/2005 to 12/2014)					
32						
33	Other PJM Integration	568,808		407.3	31,285	537,523
34	Per FERC Docket No AC04-101-000					
35	(Amort. period from 01/2005 to 12/2019)					
36						
37	Carrying Charges - RTO Startup Costs	551,415	271,760	407.3	317,659	505,516
38	Per FERC Docket Nos AC04-101-000 & EL05-74-000					
39	(Amort. periods from 01/2005 up to 12/2019)					
40						
41	Alliance RTO Deferred Expense	497,667		407.3	27,372	470,295
42	Per FERC Docket No AC04-101-000					
43	(Amortization period from 01/2005 to 12/2019)					
44	TOTAL	293,112,866	490,163,573		448,560,847	334,715,592

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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 (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1						
2	Def Equity Carrying Charge OH RSP Filing Cost	(31,254)		421	14,253	-45,507
3						
4	Carrying Charge OH RSP Filing Cost	55,838	23,689			79,527
5						
6	Ohio Line Extension - Equity Charges	(22,271,245)	686,116	421, 456	8,124,203	-29,709,332
7						
8	Unrecovered Fuel Cost		248,019,807	501, 254	211,991,674	36,028,133
9	Ohio ESP - Case No. 08-917-EL-SSO					
10						
11	Carrying Charge - Under-Recovered Ohio TCR	170,820	175,545	Various	346,365	
12	- Docket No. 05-1194-EL-UNC					
13						
14	Carrying Charge - Equity Ohio TCR	(66,185)	57,296	421	8,259	-17,148
15	- Docket No. 05-1194-EL-UNC					
16						
17	Carrying Charges - Monongahela Power Acquisition	1,473,168	1,793,952	421	467,334	2,799,786
18						
19	Equity Carrying Charge - Mon Power Acquisition	(701,148)		421	659,558	-1,360,706
20						
21	SFAS 158 Employers' Accounting for Defined	187,820,699	175,510,762	Various	188,307,121	175,024,340
22	Benefit Pension and Other Postretirement Plans					
23						
24	Ohio Green Power Pricing Program	136,310	15,346	557	21	151,635
25	-Case No 06-1153-EL-UNC					
26						
27	Carry Chgs-Deferred Storm Exp-Hurricane Ike	148,238	984,345			1,132,583
28	Ohio Wind Storm - Case No. 08-1301-EL-AAM					
29						
30	Carrying Charges - Ohio Fuel Adjustment Clause		4,136,075	421	2,255,176	1,880,899
31	Ohio ESP - Case No. 08-917-EL-SSO					
32						
33	Under-Recovered Enhanced SVC Reliability Plan Costs		3,057,820	593	996,607	2,061,213
34	Ohio ESP - Case No. 08-917-EL-SSO					
35						
36	EDR - Carrying Charges		59,668			59,668
37	- EDR - Economic Development Rider					
38	- Case No. 09-119-EL-AEC					
39						
40	EDR - Deferral		11,396,605	182.3	1,247,086	10,149,519
41	- EDR - Economic Development Rider					
42	- Case Nos. 09-119-EL-AEC & 09-516-EL-AEC					
43						
44	TOTAL	293,112,866	490,163,573		448,560,847	334,715,592

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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						
2	SFAS 109 Deferred FIT	18,540,294	17,697,122	Various	24,104,326	12,133,090
3						
4	SFAS 109 Deferred SIT	1,385,797	216,304	283.3	61,057	1,541,044
5						
6	Monongahela Power Integration Cost	3,840,862	1,058,795	Various	108,447	4,791,210
7						
8	Monongahela Power Litigation Termination	4,935,095	467,335	407.3	2,541,358	2,861,072
9	-Case No 05-765-EL-UNC					
10						
11	Monongahela Power Acqd Net Reg Asset	4,052,126				4,052,126
12						
13						
14						
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24						
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38						
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40						
41						
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43						
44	TOTAL	293,112,866	490,163,573		448,560,847	334,715,592

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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		1,257,817	Various	1,249,662	8,155
2						
3	Deferred Property Taxes	89,949,730	98,815,767	Various	91,451,568	97,313,929
4						
5	Agency Fees - Factored A/R	2,898,538	33,437,111	Various	32,953,755	3,381,894
6						
7	Defd Prop Tax - Capital Leases		300,500	408.1	300,250	250
8						
9	Labor Accruals	1,533,590	6,559,214	Various	8,092,804	
10						
11	CCPC Coal Washing Costs		8,557,612	151	8,535,515	22,097
12						
13	Nontraditional Option Premiums		1,082,541	232	1,020,064	62,477
14						
15	Unamortized Credit Line Fees	120,159		431	49,816	70,343
16						
17	Defd Depr&Capcty Portion-Affil	2,075,642	6,110,916			8,186,558
18						
19	Deferred Expenses - Current		149,202	Various	143,330	5,872
20						
21	Defd Lease Assets - Non Taxable		691,198	Various	679,079	12,119
22						
23						
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46						
47	Misc. Work in Progress	2,356,854				772,076
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	98,934,513				109,835,770

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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	Impaired Asset Reserve FAS 121	315,000	315,000
3	Interest Expense Capitalized for Tax	20,780,385	26,292,177
4	Mark to Market	18,080,675	-8,460,215
5	Contribution in Aid of Construction	17,323,446	15,206,883
6	SEC Allocation of Investment Tax Credit - Generation Plant	5,678,766	5,678,766
7	Other	55,790,366	49,592,222
8	TOTAL Electric (Enter Total of lines 2 thru 7)	117,968,638	88,624,833
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify)	32,108,183	30,335,378
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	150,076,821	118,960,211

Notes

Line 17 Other - Detail	Beginning Balance	Ending Balance
Non-Utility - 190.2	3,082,664	3,878,545
SFAS 109 - 190.3 & 190.4	2,761,168	1,435,380
SFAS 133 - 190.0006	212,349	633,252
SFAS 87 - 190.0009	26,052,002	24,388,201
	32,108,183	30,335,378

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

Balance at Beginning of Year	$150,076,821
(Less) Amounts Debited to:	
(a) Account 410.1	(71,149,426)
(b) Account 410.2	(2,634,508)
(c) Various	(36,383,905)
(Plus) Amounts Credited to:	
(a) Account 411.1	50,558,621
(b) Account 411.2	3,430,389
(c) Various	25,062,219
Balance at End of Year	$118,960,211

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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	24,000,000	2.50	
2				
3	TOTAL_COM	24,000,000		
4				
5	PREFERRED STOCK: NONE			
6				
7				
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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)	
16,410,426	41,026,065					1
						2
16,410,426	41,026,065					3
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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	Account 208 - Donations Received from Stockholders	332,200,000
2	Subtotal	332,200,000
3		
4	Account 209 - Reduction in Par or Stated Value of Capital Stock: NONE	
5		
6	Account 210 - Gain(Loss) on Resale or Cancellation of Reacq Capital	
7	Beginning Balance	-1,838,730
8	Amort. of Loss on Redemption of 9.50% Cumulative Preferred Stock	59,092
9	Amort. of Loss on Redemption of 7.875% Cumulative Preferred Stock	40,729
10	Amort. of Preferred Stock Issuance Expense	57,620
11	Subtotal	-1,681,289
12		
13	Account 211 - Miscellaneous Paid-in Capital	
14	Common Stock - 1971-1975	-3,623,206
15	- 2 Million Common 5/76	-1,617,944
16	- 1 Million Common 11/76	-882,066
17	- 2 Million Common 10/77	-1,514,091
18	- Thrift and DRIP	-109,177
19	Subtotal	-7,746,484
20		
21		
22		
23		
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26		
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40	TOTAL	322,772,227

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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		
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21		
22	TOTAL	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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	NONE		
3			
4	ACCOUNT 222 - REACQUIRED BONDS		
5			
6	Ohio Air Quality Development Rev Bonds 2.15% Floating Series C Due 2038	-43,695,000	
7			
8	Ohio Air Quality Development Rev Bonds 2.35% Floating Series D Due 2038	-48,550,000	
9			
10	SUBTOTAL (ACCOUNT 222)	-92,245,000	
11			
12	ACCOUNT 223 - ADVANCES FROM ASSOC COMPANIES		
13			
14	4.64% Notes Payable Affiliated Due 2010	100,000,000	
15			
16	SUBTOTAL (ACCOUNT 223)	100,000,000	
17			
18	ACCOUNT 224 - OTHER LONG-TERM DEBT		
19			
20	Ohio Air Quality Development Rev Bonds 2.15% Floating Series C Due 2038	43,695,000	600,000
21			
22			
23	Ohio Air Quality Development Rev Bonds 2.35% Floating Series D Due 2038	48,550,000	1,348,440
24			169,925 D
25			
26	5.50% Unsecured Medium Term Notes Series A Due 2013	250,000,000	1,625,000
27			657,500 D
28			
29			
30	6.60% Unsecured Medium Term Notes Series B Due 2033	250,000,000	2,187,500
31			1,180,000 D
32			
33	TOTAL	1,542,745,000	20,294,475

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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	4.40% Unsecured Medium Term Notes Series E Due 2010	150,000,000	937,500
3			315,000 D
4			
5	5.85% Unsecured Medium Term Notes Series F Due 2035	250,000,000	2,187,500
6			2,815,000 D
7			
8	6.05% Unsecured Medium Term Notes Series G Due 2018	350,000,000	2,347,096
9			791,000 D
10			
11	Ohio Air Quality Revenue Bonds 4.85% Series 2007A Due 2040	44,500,000	928,466
12	*Bond subject to mandatory tender for purchase (puttable) on 05/01/12		
13			
14	Ohio Air Quality Revenue Bonds 5.10% Series 2007B Due 2042	56,000,000	1,101,717
15	*Bond subject to mandatory tender for purchase (puttable) on 05/01/13		
16			
17	Ohio Air Quality Revenue Bonds 3.875% Series 2009A Due 2038	60,000,000	656,061
18	PUCO Case No. 09-314-EL-AIS dated 06/17/2009		
19	*Bond subject to mandatory tender for purchase (puttable) on 06/01/14		
20			
21	Ohio Air Quality Revenue Bonds 5.80% Series 2009B Due 2038	32,245,000	446,770
22	PUCO Case No. 09-314-EL-AIS dated 06/17/2009		
23			
24			
25	Brokerage Fees on Auction Rate Notes		
26			
27	SUBTOTAL (ACCOUNT 224)	1,534,990,000	20,294,475
28			
29	Footnote		
30			
31			
32			
33	TOTAL	1,542,745,000	20,294,475

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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
05/20/08	12/01/38				-156,763	6
						7
04/22/08	12/01/38				-140,423	8
						9
					-297,186	10
						11
						12
						13
08/18/04	03/15/10			100,000,000	4,640,001	14
						15
				100,000,000	4,640,001	16
						17
						18
						19
04/29/04	12/01/38				156,763	20
						21
						22
07/29/04	12/01/38				144,184	23
						24
						25
02/14/03	03/01/13	02/14/03	03/01/13	250,000,000	13,750,000	26
						27
						28
						29
02/14/03	03/01/33	02/14/03	03/01/33	250,000,000	16,500,000	30
						31
						32
				1,542,745,000	83,846,255	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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
11/25/03	12/01/10	11/25/03	12/01/10	150,000,000	6,600,000	2
						3
						4
10/14/05	10/01/35	10/14/05	10/01/35	250,000,000	14,625,000	5
						6
						7
05/16/08	05/01/18	05/16/08	05/01/18	350,000,000	21,175,000	8
						9
						10
08/15/07	08/01/40	08/15/07	05/01/12	44,500,000	2,158,250	11
						12
						13
11/20/07	11/01/42	11/20/07	05/01/13	56,000,000	2,856,000	14
						15
						16
08/19/09	12/01/38	08/19/09	06/01/14	60,000,000	852,500	17
						18
						19
						20
08/19/09	12/01/38	08/19/09	12/01/38	32,245,000	685,743	21
						22
						23
						24
						25
						26
				1,442,745,000	79,503,440	27
						28
						29
						30
						31
						32
				1,542,745,000	83,846,255	33

FOOTNOTE DATA

Schedule Page: 256 Line No.: 20 Column: a

Upon early redemption of the Series C 2.15% Floating Ohio Air Quality Development Revenue Bonds on 08/19/09, the unamortized issuance expenses, discounts and losses were expensed to Account 426.

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

Upon early redemption of the Series D 2.35% Floating Ohio Air Quality Development Revenue Bond on 08/19/09, the unamortized issuance expenses, discounts and losses were expensed to Account 426.

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

Ohio Air Quality Revenue Bonds 4.85% Series 2007A has a "Put Date" of 05/01/12.

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

Ohio Air Quality Revenue Bonds 5.10% Series 2007B has a Mandatory Tender Date (PUT Date) of 05/01/13.

Schedule Page: 256.1 Line No.: 17 Column: e

Ohio Air Quality Revenue Bonds 3.875% Series 2009A has a Mandatory Tender Date (PUT Date) of 06/01/14.

Schedule Page: 256.1 Line No.: 29 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 $139,564 on reallocated off-system sales margins between AEP East and West Companies as ordered by the FERC.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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)	271,661,103
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	40,018,904
28	Show Computation of Tax:	
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		

FOOTNOTE DATA

Schedule Page: 261 Line No.: 27 Column: b

NET INCOME FOR THE YEAR PER PAGE 117	271,661
FEDERAL INCOME TAXES	139,247
STATE INCOME TAXES	4,452
PRETAX BOOK INCOME	415,360
INCREASE (DECREASE) IN TAXABLE INCOME RESULTING FROM:	
ACCELERATED AMORTIZATION	(34,764)
ACCRD BOOK ARO EXPENSE - SFAS 143	1,210
ACCRD OPEB COSTS	(11,146)
ACCRD LOW INCOME HOUSING OBLIGATIONS	5,062
ACCRUED INT -LONG & SHORT TERM	910
AFUDC / INTEREST CAPITALIZED	7,297
CAPITALIZED RELOCATION COSTS	(4,100)
DEFD CREDITS - DEFD DEPR & CAPACITY COSTS	(6,111)
DEFD STORM DAMAGE	286
EMISSION ALLOWANCES	(9,178)
EQUITY IN EARNINGS OF SUBSIDIARIES	(298)
EXCESS TAX vs BOOK DEPRECIATION	(125,163)
MARK-TO-MARKET	(27,715)
MITIGATION PROGRAMS - FED & STATE	(1,802)
OTHER	2,848
PENSION, NET	(1,703)
PERCENT REPAIR ANALYSIS	(2,400)
BOOK/TAX UNIT OF PROPERTY ADJ.	(85,334)
REG ASSET - NET	2,855
DEFERRED FUEL COSTS	(37,909)
REMOVAL COSTS	(6,390)
REVENUE REFUNDS	(45,402)
CHARITABLE CONTRIBUTION CFWD	4,978
ACCRUED STATE INCOME TAX RES	(543)
FEDERAL TAX NET INCOME - ESTIMATED CURRENT YEAR TAXABLE INCOME - BEFORE STATE INCOME TAXES (SEPARATE RETURN BASIS)	40,848
CURRENT YEAR STATE INCOME TAX	(829)
	40,019

Computation of Tax *

Federal Income Tax on Current Year Taxable Income (Separate Return Basis) at the Statutory Rate of 35%		14,007
Adjustment due to System Consolidation	(a)	(2,973)
Estimated Tax Currently Payable	(b)	11,034
Tax Provision Adjustment		(1,507)
Adjustment of Prior Year's Accruals (Net)		3,515
Estimated Current Federal Income Taxes (Net)		13,042

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
Columbus Southern 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 Taxes:					
2	Income Tax	729,327		14,548,477	44,352,972	703,088
3	FICA - 2009	989,436		6,569,277	7,135,661	
4	Unemployment - 2009	39,118		49,403	76,708	
5	Payroll Taxes - CCD			886,143	886,143	
6	Federal Excise Tax - 2009			5,328	5,328	
7	SUBTOTAL	1,757,881		22,058,628	52,456,812	703,088
8						
9	State of Ohio:					
10	KWH Ohio Excise-2008	6,368,717			6,368,717	
11	KWH Ohio Excise-2009			69,162,456	63,263,177	
12	OCC & PUCO FEES-2009			2,756,472	2,756,472	
13	Ohio CAT Tax - 2008	865,003		50,421	915,424	
14	Ohio CAT Tax - 2009			5,012,233	3,810,733	
15	Sales & Use - 2008	171,048	83,476	-56,757	30,815	
16	Sales & Use - 2009			934,133	771,504	
17	Sales & Use - Audit Prov	100,000				
18	Unemployment - OH 2009	69,096		123,332	171,503	
19	Ohio Income Tax - 2008	67,705		-446,861	-379,156	
20	Ohio Franch 2007 & Prior				-57,383	-57,383
21	Ohio Franchise Tax - 2009			29,968	30,049	81
22	Ohio City Tax - 2007 & Prior				-32,027	-32,027
23	Ohio City Tax - 2008	-455,269		353,766	-75,404	26,099
24	Ohio City Tax - 2009			767,024	1,743,182	2,765
25	SUBTOTAL	7,186,300	83,476	78,686,187	79,317,606	-60,465
26	KY Cities	-592		592		
27	KY Income Tax - 2007 & Prior	593		256	849	
28	KY Income Tax - 2008	-106,892		-192,392	-299,284	
29	KY Income Tax - 2009			34,007	449,284	
30	SUBTOTAL	-106,891		-157,537	150,849	
31						
32	WV Income Tax-2008	176,336		4,215	180,551	
33	WV Income Tax-2009			72,084		
34	West Virginia Fran Tax - 2008	-7,572		1,690	-5,882	
35	West Virginia Fran Tax - 2009			118,750	174,101	
36	SUBTOTAL	168,764		196,739	348,770	
37						
38						
39						
40						
41	TOTAL	187,000,423	83,476	200,197,092	219,459,634	110,813

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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	Real & Pers. Prop - 2004 OH			55,470	55,470	
2	Real & Pers. Prop - 2005 OH			55,470	55,470	
3	Real & Pers. Prop - 2007 OH	84,739,711		1,341,799	86,081,510	
4	Real & Pers. Prop - 2008 OH	89,908,730		1,496,331	-3,669	
5	Real & Pers. Prop - 2009 OH			97,277,929		
6						
7	Pers Prop Leased-2005 OH	85,280				
8	Pers Prop Leased-2006 OH	199,735		-66,933	132,802	
9	Pers Prop Leased-2007 OH	200,016		27,428	227,444	
10	Pers Prop Leased-2008 OH	200,016		43,317	243,333	
11	Pers Prop Leased-2009 OH			300,000		
12						
13	Pers Prop Leased-2007 WV	243			243	
14	Pers Prop Leased-2008 WV			453	453	
15	Pers Prop Leased-2009 WV			500		
16						
17	Real Prop Leased - 2008 OH	22,600		566	23,166	
18	Real Prop Leased - 2009 OH			22,836		
19						
20	Real & Pers Prop - 2007 KY	16,439		-1,810	14,629	
21	Real & Pers Prop - 2008 KY	41,000		-4,712	36,288	
22	Real & Pers Prop - 2009 KY			36,000		
23						
24	Real & Pers. Prop - 2009 LA			485	485	
25	SUBTOTAL	175,413,770		100,585,129	86,867,624	
26						
27	Other Than Income Tax:					
28	State Lic Tax 2008 & Prior			20,466	20,466	
29	State Lic Tax 2009			410	410	
30	Fed Income Tax - Audit	130,000		-130,000		
31	SUBTOTAL	130,000		-109,124	20,876	
32						
33	Fed Inc Tx- FIN48	1,864,490		-1,376,710		-589,193
34	State Inc Tx- FIN48	504,513		-543,621		57,383
35	SUBTOTAL	2,369,003		-1,920,331		-531,810
36	MI Income - 2008	81,596		276,359	357,955	
37	MI Income - 2009			403,000	-173,955	
38	SUBTOTAL	81,596		679,359	184,000	
39						
40						
41	TOTAL	187,000,423	83,476	200,197,092	219,459,634	110,813

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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	Illinois Income - 2008			81,866	81,866	
2	Illinois Income - 2009			96,176	31,231	
3	SUBTOTAL			178,042	113,097	
4						
5						
6						
7						
8						
9						
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26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	187,000,423	83,476	200,197,092	219,459,634	110,813

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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
-28,372,080		20,782,733			-6,234,256	2
423,052		3,870,326			2,698,951	3
11,813		24,799			24,604	4
		886,143				5
		5,328				6
-27,937,215		25,569,329			-3,510,701	7
						8
						9
						10
5,899,279		69,162,456				11
		2,756,472				12
		50,421				13
1,201,500		5,012,233				14
		520			-57,277	15
227,629	65,000	6,598			927,535	16
100,000						17
20,925		51,461			71,871	18
		-549,505			102,644	19
						20
		29,968				21
						22
		301,185			52,581	23
-973,393		678,843			88,181	24
6,475,940	65,000	77,500,652			1,185,535	25
		592				26
		849			-593	27
		-189,087			-3,305	28
-415,277		30,900			3,107	29
-415,277		-156,746			-791	30
						31
		-9,209			13,424	32
72,084		52,360			19,724	33
		1,690				34
-55,351		118,750				35
16,733		163,591			33,148	36
						37
						38
						39
						40
167,830,218	65,000	194,963,281			5,233,811	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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)	
		55,470				1
		55,470				2
		1,303,169			38,630	3
91,408,730		91,293,930			-89,797,599	4
97,277,929					97,277,929	5
						6
85,280						7
		-66,933				8
		27,428				9
		43,317				10
300,000		300,000				11
						12
						13
		453				14
500		250			250	15
						16
		566				17
22,836		22,836				18
						19
		-1,810				20
		36,288			-41,000	21
36,000					36,000	22
						23
		485				24
189,131,275		93,070,919			7,514,210	25
						26
						27
		20,466				28
		410				29
		-130,000				30
		-109,124				31
						32
-101,413		-1,376,710				33
18,275		-543,621				34
-83,138		-1,920,331				35
		273,982			2,377	36
576,955		403,000				37
576,955		676,982			2,377	38
						39
						40
167,830,218	65,000	194,963,281			5,233,811	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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)	
		75,822			6,044	1
64,945		92,187			3,989	2
64,945		168,009			10,033	3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
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						35
						36
						37
						38
						39
						40
167,830,218	65,000	194,963,281			5,233,811	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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%	5,206			4114	2,602	
4	7%						
5	10%	18,807,877			4114	1,977,522	
6							
7							
8	TOTAL	18,813,083				1,980,124	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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
2,604	Various		3
			4
16,830,355	Various		5
			6
			7
16,832,959			8
			9
			10
			11
			12
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			47
			48

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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-Noncurrent		Various	25,690	805,815	780,125
2						
3	Allowances	242,715	186, 234	374,715	132,000	
4						
5	Customer Advance Receipts	8,392,446	Various	93,142,715	89,022,728	4,272,459
6						
7	Deferred Rev - Pole Attachments	86,897	Various	1,226,877	1,390,763	250,783
8						
9	SFAS 106 - OPEB	6,893,927	Various	1,991,653	1,812,852	6,715,126
10						
11	Est 1 Mo O&M Beckjord / Zimmer	2,050,971	506, 512	4,199,758	2,148,787	
12						
13	Est 1 Mo O&M for Stuart	3,308,621	506, 512	9,984,721	6,676,100	
14						
15	MACSS Unidentified EDI Cash	497	Various	504,952	510,533	6,078
16						
17	Other Deferred Credit-Current	313,619	Various	333,042	317,875	298,452
18						
19	State Mitigation Deferral (NSR)	2,767,536	242	922,512		1,845,024
20						
21	Federal Mitigation Deferrel (NSR)	4,605,641	242	570,804		4,034,837
22						
23	Fiber Optic Lines-Sold-Defd Rev	1,621,901	451	114,730		1,507,171
24	(Various amortization periods					
25	up to 12/2024)					
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
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41						
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43						
44						
45						
46						
47	TOTAL	30,284,771		113,392,169	102,817,453	19,710,055

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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	7,434,999	12,247,409	
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	7,434,999	12,247,409	
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)	7,434,999	12,247,409	
18	Classification of TOTAL			
19	Federal Income Tax	7,434,999	12,247,409	
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
Columbus Southern 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
						19,682,408	4
							5
							6
							7
						19,682,408	8
							9
							10
							11
							12
							13
							14
							15
							16
						19,682,408	17
							18
						19,682,408	19
							20
							21

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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	447,874,446	116,398,915	34,598,649
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	447,874,446	116,398,915	34,598,649
6	Non-Utility	-1,441,896		
7	SFAS 109	9,471,120		
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	455,903,670	116,398,915	34,598,649
10	Classification of TOTAL			
11	Federal Income Tax	455,903,670	116,398,915	34,598,649
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
Columbus Southern 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
		216.1	166,957	146.1	875,011	530,382,766	2
							3
							4
			166,957		875,011	530,382,766	5
	10,281			146.1	890	-1,451,287	6
		Various	15,643,964	Various	11,912,306	5,739,462	7
							8
	10,281		15,810,921		12,788,207	534,670,941	9
							10
	10,281		15,810,921		12,788,207	534,670,941	11
							12
							13

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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	Emission Allowances	6,121,854	5,998,260	2,444,088
4	Capitalized Software	5,374,440	2,539,962	1,622,005
5	Pension Expense	22,693,160	1,712,089	35,874,640
6	Mark to Market	23,950,666	17,968,096	32,315,416
7	Loss on Reacquired Debt	3,535,150		260,224
8	Other	58,580,486	87,841,982	17,454,049
9	TOTAL Electric (Total of lines 3 thru 8)	120,255,756	116,060,389	89,970,422
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other NonUtility/SFAS 109 & 13	3,763,427		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	124,019,183	116,060,389	89,970,422
20	Classification of TOTAL			
21	Federal Income Tax	118,497,044	112,311,525	89,767,470
22	State Income Tax	5,522,139	3,748,864	202,952
23	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	(k)	
							1
							2
						9,676,026	3
						6,292,397	4
						-11,469,391	5
						9,603,346	6
						3,274,926	7
		190.1	8,753,000			120,215,419	8
			8,753,000			137,592,723	9
							10
							11
							12
							13
							14
							15
							16
							17
511,864	8,702,993	Various	8,462,415	Various	5,823,703	-7,066,414	18
511,864	8,702,993		17,215,415		5,823,703	130,526,309	19
							20
511,864	8,702,993		17,154,358		5,607,399	121,303,011	21
			61,057		216,304	9,223,298	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	(5,633,468)	(13,824,598)
SFAS 109	8,359,929	6,326,991
SFAS 133	1,036,966	431,193
Total	$ 3,763,427	$ (7,066,414)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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	3,486,696	175	12,412,636	8,925,940	
2						
3	Ohio RSP-Low Income Customer / Econ Recovery	2,351,000				2,351,000
4	Docket No. 04-169-EL-UNC					
5						
6	Over-Recovered CSP PAR	1,517,645	182.3	1,517,645		
7						
8	Over-Recovered Ohio TCR Rider	608,790	447	18,418,030	32,620,170	14,810,930
9	Docket No. 05-1194-EL-UNC					
10						
11	Carrying Charge - Over-Recovered Ohio TCR		Various	312,630	689,313	376,683
12	Docket No. 05-1194-EL-UNC					
13						
14	IGCC Pre-Construction Costs Net Recovery	1,831,500	182.3	8,396	172	1,823,276
15	Docket No. 05-376-EL-UNC					
16						
17	Over-Recovered gSMART Misc Dist Expense		254, 588	534,724	4,320,462	3,785,738
18	Ohio ESP - Case No. 08-917-EL-SSO					
19						
20	Over-Recovered gSMART Debt Carrying Charge		431	5,916	839,070	833,154
21	Ohio ESP - Case No. 08-917-EL-SSO					
22						
23	Over-Recovered gSMART Equity Carrying Charge		426.5	4,034	725,390	721,356
24	Ohio ESP - Case No. 08-917-EL-SSO					
25						
26	Over-Recovered gSMART Depr / A&G Expense		930.2	3,082	2,139,588	2,136,506
27	Ohio ESP - Case No. 08-917-EL-SSO					
28						
29	SFAS 109 Deferred FIT	4,856,211	Various	2,063,687	250,537	3,043,061
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	14,651,842		35,280,780	50,510,642	29,881,704

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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	749,622,708	720,760,928
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	715,726,606	684,277,108
5	Large (or Ind.) (See Instr. 4)	267,791,467	330,371,313
6	(444) Public Street and Highway Lighting	6,341,432	5,872,421
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	1,739,482,213	1,741,281,770
11	(447) Sales for Resale	281,037,292	525,547,264
12	TOTAL Sales of Electricity	2,020,519,505	2,266,829,034
13	(Less) (449.1) Provision for Rate Refunds		30,359,010
14	TOTAL Revenues Net of Prov. for Refunds	2,020,519,505	2,236,470,024
15	Other Operating Revenues		
16	(450) Forfeited Discounts	2,827,686	2,879,798
17	(451) Miscellaneous Service Revenues	2,259,332	2,392,680
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	17,232,043	16,331,184
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	783,438	5,094,391
22	(456.1) Revenues from Transmission of Electricity of Others	13,478,421	14,474,037
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	36,580,920	41,172,090
27	TOTAL Electric Operating Revenues	2,057,100,425	2,277,642,114

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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
7,303,192	7,550,528	667,018	665,306	2
				3
8,532,204	8,771,995	78,482	78,052	4
4,783,906	5,827,886	3,384	3,431	5
54,167	55,242	308	310	6
				7
				8
				9
20,673,469	22,205,651	749,192	747,099	10
5,862,120	9,483,574	103	107	11
26,535,589	31,689,225	749,295	747,206	12
				13
26,535,589	31,689,225	749,295	747,206	14

Line 12, column (b) includes $ 7,029,858 of unbilled revenues.

Line 12, column (d) includes -1,137 MWH relating to unbilled revenues

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

Detail of Unmetered Sales included in Total Sales to Ultimate Customers:

	Revenues	MWH Sold	Average No. of Customers
(440) Residential	2,231,529	11,329	15,513
(442) Commercial	9,251,406	51,722	11,854
(442) Industrial	351,863	2,398	431
(444) Street Lighting	6,334,675	54,282	308
	18,169,473	119,731	28,106

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

Customer Service Revenues (1)	2,346,534
All other under $250,000 each	-87,202
	2,259,332

(1) - Includes connect, reconnect, disconnect and other service charges.

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

Financial Trading Revenue - Unrealized	-4,497,721
Ohio Line Extension Construction	3,365,956
Coal Trading Realized - Gain/Loss	1,180,748
Associated Business Development	730,355
All other under $250,000 each	4,100
	783,438

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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					
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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
Columbus Southern 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	R-R Residential Service	6,366,477	644,999,319	485,499	13,113	0.1013
3	R-R-1 Res Small Use Load Mgt	931,610	98,555,696	181,438	5,135	0.1058
4	RLM Res Optional Demand Rate	6,213	480,936	71	87,507	0.0774
5	RS-ES Res Energy Storage	17	1,891	2	8,500	0.1112
6	RS-TOD Res Time-of-Day	61	6,121	7	8,714	0.1003
7	GS-1 General Service-Small	25	2,168			0.0867
8	AL Private Area Lighting	11,329	2,231,529			0.1970
9	OAD-R-R Open Access Res Svc	7	299	1	7,000	0.0427
10	Subtotal-Billed	7,315,739	746,277,959	667,018	10,968	0.1020
11	Net Unbilled	-12,547	3,344,749			-0.2666
12	Total-Residential	7,303,192	749,622,708	667,018	10,949	0.1026
13						
14						
15	442-Commercial					
16	R-R Residential Service	24	2,094			0.0873
17	GS-1 General Service-Small	328,976	41,668,263	49,560	6,638	0.1267
18	GS-2 Gen Svc-Low Load Factor	1,513,671	168,250,767	23,039	65,700	0.1112
19	GS-2-TOD Gen Svc- Time-of-Day	10,498	959,414	113	92,903	0.0914
20	GS-3 Gen Svc-Med Load Factor	5,615,892	445,549,764	5,309	1,057,806	0.0793
21	GS-4 General Service-Large	871,389	44,510,252	10	87,138,900	0.0511
22	SL Street Lighting	239	17,929	3	79,667	0.0750
23	AL Private Area Lighting	41,568	8,304,127			0.1998
24	OAD-GS-1 Open Access GS-Small	622	20,977	42	14,810	0.0337
25	OAD-GS-2 Open Acc GS-Low Load	64,347	1,666,224	312	206,240	0.0259
26	OAD-GS-3 Open Acc GS-Med Load	76,583	1,834,527	94	814,713	0.0240
27	OAD-AL Open Acc Priv Area Light	2	265			0.1325
28	Net Estimated Billings	-133	-9,343			0.0702
29	Subtotal-Billed	8,523,678	712,775,260	78,482	108,607	0.0836
30	Net Unbilled	8,526	2,951,346			0.3462
31	Total-Commercial	8,532,204	715,726,606	78,482	108,715	0.0839
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	20,674,606	1,732,452,355	749,192	27,596	0.0838
42	Total Unbilled Rev.(See Instr. 6)	-1,137	7,029,858	0	0	-6.1828
43	TOTAL	20,673,469	1,739,482,213	749,192	27,594	0.0841

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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	442-Industrial					
2	GS-1 General Service-Small	8,492	1,113,311	1,678	5,061	0.1311
3	GS-2 Gen Svc-Low Load Factor	163,988	19,211,076	1,192	137,574	0.1171
4	GS-2-TOD Gen Svc- Time-of-Day	529	53,909	1	529,000	0.1019
5	GS-3 Gen Svc-Med Load Factor	1,341,754	101,767,903	477	2,812,901	0.0758
6	GS-4 General Service-Large	3,239,790	143,406,270	23	140,860,435	0.0443
7	AL Private Area Lighting	2,351	347,250			0.1477
8	IRP-D Interruptible Power Discret	17,923	981,106	1	17,923,000	0.0547
9	OAD-GS-1 Open Access GS-Small	10	356	1	10,000	0.0356
10	OAD-GS-2 Open Acc GS-Low Load	5,324	162,933	10	532,400	0.0306
11	OAD-GS-3 Open Acc GS-Med Low	746	20,347	1	746,000	0.0273
12	Subtotal-Billed	4,780,907	267,064,461	3,384	1,412,798	0.0559
13	Net Unbilled	2,999	727,006			0.2424
14	Total-Industrial	4,783,906	267,791,467	3,384	1,413,684	0.0560
15						
16						
17	444-Street & Highway Lighting					
18	GS-1 General Service-Small	13,503	1,222,895	101	133,693	0.0906
19	SL Street Lighting	40,779	5,111,780	207	197,000	0.1254
20	Subtotal-Billed	54,282	6,334,675	308	176,240	0.1167
21	Net Unbilled	-115	6,757			-0.0588
22	Total-Str & Highway Lighting	54,167	6,341,432	308	175,867	0.1171
23						
24						
25	Fuel Adj Clause - See Footnote					
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	20,674,606	1,732,452,355	749,192	27,596	0.0838
42	Total Unbilled Rev.(See Instr. 6)	-1,137	7,029,858	0	0	-6.1828
43	TOTAL	20,673,469	1,739,482,213	749,192	27,594	0.0841

Schedule Page: 304.1 Line No.: 25 Column: a

Fuel Adjustment Clause - Estimated Additional Revenue

440-Residential	
R-R Residential Service	131,883,426
R-R-1 Res Small Use Load Mgt	18,737,064
RLM Res Optional Demand Rate	129,491
RS-ES Res Energy Storage	306
RS-TOD Res Time-of-Day	1,317
GS-1 General Service - Small	91
AL Private Area Lighting	283,423
Total Billed	151,035,118
Unbilled	11,841,321
Total	162,876,439
442-Commercial	
R-R Residential Service	340
GS-1 General Service - Small	6,722,378
GS-2 Gen Svc - Low Load Factor	31,208,967
GS-2-TOD Gen Svc - Time-of-Day	213,417
GS-3 Gen Svc - Med Load Factor	121,742,466
GS-4 General Service - Large	18,816,261
SL Street Lighting	5,851
AL Private Area Lighting	1,039,614
Net Estimated Billings	8,608
Total Billed	179,757,902
Unbilled	10,764,729
Total	190,522,631
442-Industrial	
GS-1 General Service - Small	168,021
GS-2 Gen Svc - Low Load Factor	3,326,546
GS-2-TOD Gen Svc - Time-of-Day	13,085
GS-3 Gen Svc - Med Load Factor	29,012,694
GS-4 General Service - Large	41,331,051
AL Private Area Lighting	59,091
IRP-D Interruptible Power Discretionary	310,662
Total Billed	74,221,150
Unbilled	2,827,132
Total	77,048,282
444-Street & Highway Lighting	
GS-1 General Service - Small	292,980
SL Street Lighting	1,006,798
Total Billed	1,299,778
Unbilled	49,136
Total	1,348,914
Total	431,796,266

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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	CITY OF WESTERVILLE	RQ	Note 1			
2	CLEVELAND PUBLIC POWER	IF	Note 1			
3	NC ELECTRIC MEMBERSHIP CORP.	IF	Note 1			
4	TOWN OF FRONT ROYAL	IF	Note 1			
5	WOLVERINE POWER SUPPLY COOP	IF	Note 1			
6	CITY OF COLUMBUS	LF	Note 1			
7	NC ELECTRIC MEMBERSHIP CORP.	LF	Note 1			
8	CAROLINA POWER & LIGHT	LU	Note 1			
9	THE BOROUGH OF PITCAIRN, PA	SF	Note 1			
10	AEP SERVICE CORPORATION	OS	30			
11	AEP SERVICE CORPORATION	OS	20			
12	ALLEGHENY ENERGY SUPPLY CO LLC	OS	Note 1			
13	ALLETE, INC. DBA MINNESOTA PWR	OS	Note 1			
14	AMEREN ENERGY MARKETING	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
Columbus Southern Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

SALES FOR RESALE (Account 447)

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Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	AMERICAN MUNICIPAL POWER-OHIO	OS	Note 1			
2	ASSOCIATED ELECT COOPERATIVE	OS	Note 1			
3	B.P. ENERGY COMPANY	OS	Note 1			
4	BALTIMORE GAS & ELECTRIC	OS	Note 1			
5	BARCLAYS BANK PLC	OS	Note 1			
6	BNP PARIBAS COMMODITY FUTURES	OS	Note 1			
7	BP AMOCO	OS	Note 1			
8	BUCKEYE POWER GENERATING, LLC	OS	Note 2			
9	BUCKEYE RURAL ELECTRIC ADMIN	OS	Note 1			
10	CALPINE POWER SERVICE COMPANY	OS	Note 1			
11	CAROLINA POWER & LIGHT	OS	Note 1			
12	CENTRAL ILLINOIS	OS	Note 1			
13	CENTRAL ILLINOIS PUBLIC SVC CO	OS	Note 1			
14	CHEVRON TEXACO	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
Columbus Southern Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

SALES FOR RESALE (Account 447)

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					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	CHEVRON USA INC	OS	Note 1			
2	CITADEL ENERGY PRODUCTS LLC	OS	Note 1			
3	CITADEL EQUITY FUND LTD.	OS	Note 1			
4	CITIGROUP ENERGY INC.	OS	Note 1			
5	CITIZENS ELECT CO & WELLSBOROUGH	OS	Note 1			
6	CITY OF COLUMBUS	OS	Note 1			
7	CITY OF DOWAGIAC, MI	OS	Note 1			
8	CITY OF LEBANON	OS	Note 1			
9	CITY OF NEW MARTINSVILLE	OS	Note 1			
10	CITY OF PHILIPPI, WEST VIRGINIA	OS	Note 1			
11	CLECO UTILITY GROUP LLC	OS	Note 1			
12	COMMONWEALTH EDISON COMPANY	OS	Note 1			
13	CONOCO INC.	OS	Note 1			
14	CONSTELLATION ENGY COMMODITIES	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
Columbus Southern Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

SALES FOR RESALE (Account 447)

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					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	CORAL POWER LLC	OS	Note 1			
2	CREDIT SUISSE ENERGY	OS	Note 1			
3	DELAWARE ELECTRIC MUNICIPAL CO	OS	Note 1			
4	DELMARVA POWER & LIGHT	OS	Note 1			
5	DIRECT ENERGY BUSINESS, LLC	OS	Note 1			
6	DOMINION EQUIPMENT INC	OS	Note 1			
7	DP&L POWER SERVICES	OS	Note 1			
8	DTE ENERGY TRADING INC.	OS	Note 1			
9	DUKE ENERGY CAROLINAS, LLC	OS	Note 1			
10	DUKE ENERGY INDIANA, INC.	OS	Note 1			
11	DUKE ENERGY KENTUCKY, INC.	OS	Note 1			
12	DUKE ENERGY TRADING	OS	Note 1			
13	DUQUESNE POWER, L.P.	OS	Note 1			
14	DYNEGY POWER MARKETING 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
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SALES FOR RESALE (Account 447)

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					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	EAGLE ENERGY PARTNER I, L.P.	OS	Note 1			
2	EAST KY POWER CO-OP POWER MKTG	OS	Note 1			
3	EDF TRADING NORTH AMERICA LLC	OS	Note 1			
4	EDISON MISSION MKTG & TRADING	OS	Note 1			
5	ENDURE ENERGY, LLC	OS	Note 1			
6	ENERGY AMERICA, LLC	OS	Note 1			
7	ENG MKTG, DIV OF AMERADA HESS	OS	Note 1			
8	ENTERGY POWER SERV	OS	Note 1			
9	EXELON GENERATION - POWER TEAM	OS	Note 1			
10	FIRSTENERGY TRADING SERVICES	OS	Note 1			
11	FPL ENERGY POWER MARKETINGINC	OS	Note 1			
12	GREAT RIVER ENERGY	OS	Note 1			
13	HARRISON RURAL ELECTRIFICATION	OS	Note 1			
14	HESS ENERGY TRADING COMPANY, L	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
Columbus Southern Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2009/Q4

SALES FOR RESALE (Account 447)

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					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	ILLINOIS MUNICIPAL ELEC AGENCY	OS	Note 1			
2	ILLINOIS POWER COMPANY	OS	Note 1			
3	INDIANA MUNICIPAL POWER AGENCY	OS	Note 1			
4	INTEGRYS ENERGY SERVICES, INC	OS	Note 1			
5	INTERSTATE POWER & LIGHT CO	OS	Note 1			
6	J ARON & COMPANY	OS	Note 1			
7	JP MORGAN VENTURES ENERGY CORP	OS	Note 1			
8	KANSAS CITY POWER & LIGHT CO	OS	Note 1			
9	KENTUCKY MUNICIPAL POWER AGNCY	OS	Note 1			
10	LEHMAN BROTHERS COMMODITY SVCS	OS	Note 1			
11	LETTERKENNY INDUSTRIL DEV AUTH	OS	Note 1			
12	LG&E UTILITIES POWER SALES	OS	Note 1			
13	LOUIS DREYFUS ENERGY SERV LP	OS	Note 1			
14	MERRILL LYNCH COMMODITIES, 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
Columbus Southern 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	MICHIGAN PUBLIC POWER AGENCY	OS	Note 1			
2	MID CONTINENT CORP.	OS	Note 1			
3	MIDAMERICAN ENERGY	OS	Note 1			
4	MIDWEST ISO	OS	Note 1			
5	MIECO INC.	OS	Note 1			
6	MIZUHO SECURITIES USA INC	OS	Note 1			
7	MORGAN STANLEY CAPT.	OS	Note 1			
8	NC ELECTRIC MEMBERSHIP CORP.	OS	Note 1			
9	NEXTERA ENERGY POWER MKTG LLC	OS	Note 1			
10	NIPSCO ENERGY MANAGEMENT	OS	Note 1			
11	NORDIC ENERGY SERVICES, LLC	OS	Note 1			
12	NRG POWER MARKETING INC.	OS	Note 1			
13	NSP ENERGY MARKETING	OS	Note 1			
14	OHIO RETAIL	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
Columbus Southern 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	OLD DOMINION ELEC.	OS	Note 1			
2	OPPD ENERGY MARKETING	OS	Note 1			
3	OTTER TAIL POWER COMPANY	OS	Note 1			
4	PARIBAS	OS	Note 1			
5	PENNSYLVANIA ELECTRIC COMPANY	OS	Note 1			
6	PENNSYLVANIA POWER COMPANY	OS	Note 1			
7	PEPCO SERVICES INC.	OS	Note 1			
8	PJM INTERCONNECTION	OS	Note 1			
9	POWEREX	OS	Note 1			
10	PP&L ENERGY PLUS CO.	OS	Note 1			
11	PPL ENERGY SUPPLY, LLC	OS	Note 1			
12	PRAIRIE POWER, INC.	OS	Note 1			
13	PRAIRIELAND ENERGY INCORPORATE	OS	Note 1			
14	PSEG ENERGY RESOURCES & TRADE	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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 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	RAINBOW ENERGY MARKETING	OS	Note 1			
2	REFCO INC.	OS	Note 1			
3	SEMPRA ENERGY SOLUTIONS, LLC	OS	Note 1			
4	SEMPRA ENERGY TRADING	OS	Note 1			
5	SHELL ENERGY N AMERICA (US) LP	OS	Note 1			
6	SOUTH CAROLINA ELECTRIC & GAS	OS	Note 1			
7	SOUTHEASTERN PUB SERV AUTH -VA	OS	Note 1			
8	SOUTHERN MARYLAND ELEC COOP INC	OS	Note 1			
9	SOUTHERN COMPANY	OS	Note 1			
10	SOUTHERN ILLINOIS POWER CO-OP	OS	Note 1			
11	STRATEGIC ENERGY LTD.	OS	Note 1			
12	TENASKA POWER SERVICES COMPANY	OS	Note 1			
13	THE BOROUGH OF PITCAIRN, PA	OS	Note 1			
14	THE ENERGY AUTHORITY	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
Columbus Southern 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	THE POTOMAC EDISON COMPANY	OS	Note 1			
2	TOWN OF FRONT ROYAL	OS	Note 1			
3	TVA BULK POWER TRADING	OS	Note 1			
4	UBS AG, LONDON BRANCH	OS	Note 1			
5	UBS SECURITIES LLC	OS	Note 1			
6	UNION ELECTRIC COMPANY	OS	Note 1			
7	UNION POWER PARTNERS	OS	Note 1			
8	WABASH VALLEY POWER ASSN INC.	OS	Note 1			
9	WASHINGTON GAS ENERGY SERVICES	OS	Note 1			
10	WASHINGTON MILLS COMPANY, INC	OS	Note 1			
11	WESTAR ENERGY INC.	OS	Note 1			
12	WISCONSIN POWER & LIGHT	OS	Note 1			
13	WOLVERINE POWER SUPPLY COOP	OS	Note 1			
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.
498,182		32,007,696		32,007,696	1
27,119		1,407,578		1,407,578	2
112,191		3,952,520		3,952,520	3
32,100	1,307,334	788,189		2,095,523	4
158,424	629,121	6,877,320		7,506,441	5
159,738		8,938,374		8,938,374	6
328,609	6,754,699	5,867,569		12,622,268	7
38	1,290,532			1,290,532	8
8		96,885		96,885	9
1,665,895		57,372,785		57,372,785	10
39,180		1,757,048		1,757,048	11
-2,617		-163,977		-163,977	12
-14,133		-1,099,685		-1,099,685	13
8,040		597,325		597,325	14
498,182	0	32,007,696	0	32,007,696	
5,363,938	9,981,686	239,047,910	0	249,029,596	
5,862,120	**9,981,686**	**271,055,606**	**0**	**281,037,292**	

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.
157,754		8,474,327		8,474,327	1
-34		5,092		5,092	2
10,957		398,976		398,976	3
35,497		3,596,728		3,596,728	4
201,318		8,158,381		8,158,381	5
		63,531		63,531	6
		-23,939		-23,939	7
		203,937		203,937	8
38,204		23,027,362		23,027,362	9
-1,976		-89,861		-89,861	10
1,447		65,476		65,476	11
		53,387		53,387	12
		103,561		103,561	13
		-15		-15	14
498,182	0	32,007,696	0	32,007,696	
5,363,938	9,981,686	239,047,910	0	249,029,596	
5,862,120	**9,981,686**	**271,055,606**	**0**	**281,037,292**	

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.
		-3,130		-3,130	1
		10		10	2
		17,318		17,318	3
80,890		1,973,075		1,973,075	4
2,112		152,441		152,441	5
-408		306,095		306,095	6
3,851		689,996		689,996	7
53,295		3,515,159		3,515,159	8
2,691		108,004		108,004	9
3,099		116,647		116,647	10
-289		-8,874		-8,874	11
142,588		5,225,656		5,225,656	12
-28,807		-2,162,460		-2,162,460	13
115,504		2,156,403		2,156,403	14
498,182	0	32,007,696	0	32,007,696	
5,363,938	9,981,686	239,047,910	0	249,029,596	
5,862,120	**9,981,686**	**271,055,606**	**0**	**281,037,292**	

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
9		551		551	1
-1,127		-4,669,386		-4,669,386	2
46,239		3,051,312		3,051,312	3
13,840		1,073,351		1,073,351	4
59		84,781		84,781	5
6,814		221,914		221,914	6
-2,222		-592,768		-592,768	7
3,700		-189,103		-189,103	8
407		-29,844		-29,844	9
		-8,034		-8,034	10
		-185		-185	11
-37,487		-1,326,477		-1,326,477	12
116,338		5,051,731		5,051,731	13
		-28,737		-28,737	14
498,182	0	32,007,696	0	32,007,696	
5,363,938	9,981,686	239,047,910	0	249,029,596	
5,862,120	**9,981,686**	**271,055,606**	**0**	**281,037,292**	

SALES FOR RESALE (Account 447) (Continued)

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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.
-144		7,963		7,963	1
8,496		555,733		555,733	2
1,403		11,857		11,857	3
-110,882		-4,378,160		-4,378,160	4
2,175		96,291		96,291	5
131		323,921		323,921	6
		76,778		76,778	7
9,454		-398,571		-398,571	8
-349,628		-3,436,143		-3,436,143	9
595,708		37,717,277		37,717,277	10
		2,884		2,884	11
		1,995		1,995	12
16,746		1,039,137		1,039,137	13
		-171,612		-171,612	14
498,182	0	32,007,696	0	32,007,696	
5,363,938	9,981,686	239,047,910	0	249,029,596	
5,862,120	**9,981,686**	**271,055,606**	**0**	**281,037,292**	

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.
9,368		383,244		383,244	1
		157,024		157,024	2
125,526		8,731,613		8,731,613	3
48,347		3,647,706		3,647,706	4
50,439		2,042,782		2,042,782	5
470,192		15,172,773		15,172,773	6
65,925		1,660,039		1,660,039	7
-9,756		-344,184		-344,184	8
1,652		99,106		99,106	9
		-80,559		-80,559	10
8,024		470,898		470,898	11
1,317		61,374		61,374	12
		-5		-5	13
		1,161,143		1,161,143	14
498,182	0	32,007,696	0	32,007,696	
5,363,938	9,981,686	239,047,910	0	249,029,596	
5,862,120	**9,981,686**	**271,055,606**	**0**	**281,037,292**	

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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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.
8,429		490,417		490,417	1
		-12,607		-12,607	2
212,449		9,450,771		9,450,771	3
8,738		-1,296,966		-1,296,966	4
		631		631	5
		-15,133		-15,133	6
-77,527		-2,190,426		-2,190,426	7
		-1,523,976		-1,523,976	8
38,616		1,993,614		1,993,614	9
		11,968		11,968	10
62		19,541		19,541	11
-9,927		-622,414		-622,414	12
		-3,667		-3,667	13
		-14,202,141		-14,202,141	14
498,182	0	32,007,696	0	32,007,696	
5,363,938	9,981,686	239,047,910	0	249,029,596	
5,862,120	**9,981,686**	**271,055,606**	**0**	**281,037,292**	

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.
75,202		4,862,366		4,862,366	1
		-3,039		-3,039	2
-12,897		-382,982		-382,982	3
		11,151		11,151	4
-3,174		-138,401		-138,401	5
32,484		2,332,251		2,332,251	6
170,046		14,063,737		14,063,737	7
486,678		14,099,328		14,099,328	8
807		42,471		42,471	9
-9,674		-320,340		-320,340	10
		-341		-341	11
28,898		2,050,328		2,050,328	12
13,016		462,506		462,506	13
-299,758		-18,800,746		-18,800,746	14
498,182	0	32,007,696	0	32,007,696	
5,363,938	9,981,686	239,047,910	0	249,029,596	
5,862,120	**9,981,686**	**271,055,606**	**0**	**281,037,292**	

SALES FOR RESALE (Account 447) (Continued)

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10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
		1,596		1,596	1
		-10,327		-10,327	2
45,721		6,210,858		6,210,858	3
19,372		749,797		749,797	4
16,541		1,465,186		1,465,186	5
-1		-54		-54	6
		-31,111		-31,111	7
7,525		797,917		797,917	8
23,614		820,968		820,968	9
39,880		1,543,875		1,543,875	10
-4,057		20,853		20,853	11
		4,544		4,544	12
614		38,581		38,581	13
5,918		221,685		221,685	14
498,182	0	32,007,696	0	32,007,696	
5,363,938	9,981,686	239,047,910	0	249,029,596	
5,862,120	**9,981,686**	**271,055,606**	**0**	**281,037,292**	

SALES FOR RESALE (Account 447) (Continued)

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MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
45,526		2,940,691		2,940,691	1
970		-59,710		-59,710	2
2,503		49,920		49,920	3
51,063		1,977,033		1,977,033	4
		-5,877,253		-5,877,253	5
-135,066		-4,296,784		-4,296,784	6
-7,761		-235,929		-235,929	7
-88,907		-1,773,279		-1,773,279	8
135,460		7,564,437		7,564,437	9
		312,389		312,389	10
3,578		-10,954		-10,954	11
115,629		6,370,240		6,370,240	12
		108,216		108,216	13
					14
498,182	0	32,007,696	0	32,007,696	
5,363,938	9,981,686	239,047,910	0	249,029,596	
5,862,120	**9,981,686**	**271,055,606**	**0**	**281,037,292**	

FOOTNOTE DATA

Schedule Page: 310 Line No.: 1 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.: 6 Column: b

The termination date of this contract is 05/31/2012.

Schedule Page: 310 Line No.: 7 Column: b

The termination date 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.: 10 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.: 11 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.: 8 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
Columbus Southern 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	8,148,995	8,079,124
5	(501) Fuel	268,128,076	325,346,119
6	(502) Steam Expenses	27,462,158	25,166,581
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	2,292,093	2,519,051
10	(506) Miscellaneous Steam Power Expenses	26,084,645	26,698,276
11	(507) Rents	-139	36,583,811
12	(509) Allowances	7,413,973	11,802,401
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	339,529,801	436,195,363
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	2,430,209	2,242,616
16	(511) Maintenance of Structures	3,373,971	2,662,948
17	(512) Maintenance of Boiler Plant	51,693,575	46,522,175
18	(513) Maintenance of Electric Plant	10,720,148	8,563,847
19	(514) Maintenance of Miscellaneous Steam Plant	2,680,460	3,133,695
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	70,898,363	63,125,281
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	410,428,164	499,320,644
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		
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses		
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)		
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering		
54	(542) Maintenance of Structures		
55	(543) Maintenance of Reservoirs, Dams, and Waterways		
56	(544) Maintenance of Electric Plant		
57	(545) Maintenance of Miscellaneous Hydraulic Plant		
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)		
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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	149,905	141,003
63	(547) Fuel	1,120,722	3,722,881
64	(548) Generation Expenses	130,583	176,842
65	(549) Miscellaneous Other Power Generation Expenses	664,797	377,678
66	(550) Rents	32,341	19,233
67	TOTAL Operation (Enter Total of lines 62 thru 66)	2,098,348	4,437,637
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	70,016	73,610
70	(552) Maintenance of Structures	3,796	26,985
71	(553) Maintenance of Generating and Electric Plant	689,048	832,088
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	160,655	178,822
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	923,515	1,111,505
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	3,021,863	5,549,142
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	533,837,229	685,081,619
77	(556) System Control and Load Dispatching	932,635	938,847
78	(557) Other Expenses	7,633,702	7,554,866
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	542,403,566	693,575,332
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	955,853,593	1,198,445,118
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	1,004,962	937,660
84	(561) Load Dispatching		
85	(561.1) Load Dispatch-Reliability	16,786	17,620
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,300,071	1,276,106
87	(561.3) Load Dispatch-Transmission Service and Scheduling	2,571	371
88	(561.4) Scheduling, System Control and Dispatch Services	2,853,695	3,266,714
89	(561.5) Reliability, Planning and Standards Development	111,146	40,498
90	(561.6) Transmission Service Studies		2
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	535,808	565,696
93	(562) Station Expenses	458,616	441,999
94	(563) Overhead Lines Expenses	10,965	350
95	(564) Underground Lines Expenses	510	
96	(565) Transmission of Electricity by Others	53,542,955	56,288,246
97	(566) Miscellaneous Transmission Expenses	1,390,945	19,040,756
98	(567) Rents	36,524	328,954
99	TOTAL Operation (Enter Total of lines 83 thru 98)	61,265,554	82,204,972
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	69,420	76,417
102	(569) Maintenance of Structures	74,869	63,266
103	(569.1) Maintenance of Computer Hardware	67,689	48,316
104	(569.2) Maintenance of Computer Software	353,403	302,707
105	(569.3) Maintenance of Communication Equipment	284,000	229,167
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	2,102,622	2,416,473
108	(571) Maintenance of Overhead Lines	2,747,590	5,501,121
109	(572) Maintenance of Underground Lines	616,073	595,133
110	(573) Maintenance of Miscellaneous Transmission Plant	54	
111	TOTAL Maintenance (Total of lines 101 thru 110)	6,315,720	9,232,600
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	67,581,274	91,437,572

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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	3,050,178	2,831,132
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	3,050,178	2,831,132
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)	3,050,178	2,831,132
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	6,256,386	6,230,253
135	(581) Load Dispatching	10,174	13,975
136	(582) Station Expenses	660,755	1,179,699
137	(583) Overhead Line Expenses	1,334,671	1,508,240
138	(584) Underground Line Expenses	2,637,965	2,924,865
139	(585) Street Lighting and Signal System Expenses	60,471	47,597
140	(586) Meter Expenses	1,438,274	1,297,651
141	(587) Customer Installations Expenses	212,309	289,825
142	(588) Miscellaneous Expenses	13,997,318	15,126,444
143	(589) Rents	2,094,128	2,992,783
144	TOTAL Operation (Enter Total of lines 134 thru 143)	28,702,451	31,611,332
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	487,690	246,131
147	(591) Maintenance of Structures	247,363	184,045
148	(592) Maintenance of Station Equipment	2,341,924	2,722,368
149	(593) Maintenance of Overhead Lines	35,161,388	22,148,500
150	(594) Maintenance of Underground Lines	3,224,876	2,931,069
151	(595) Maintenance of Line Transformers	432,107	674,130
152	(596) Maintenance of Street Lighting and Signal Systems	156,830	207,293
153	(597) Maintenance of Meters	173,504	251,169
154	(598) Maintenance of Miscellaneous Distribution Plant	1,352,158	1,589,830
155	TOTAL Maintenance (Total of lines 146 thru 154)	43,577,840	30,954,535
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	72,280,291	62,565,867
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	1,201,339	1,291,423
160	(902) Meter Reading Expenses	4,220,027	4,833,074
161	(903) Customer Records and Collection Expenses	23,995,865	24,640,129
162	(904) Uncollectible Accounts	21,443,093	25,478,660
163	(905) Miscellaneous Customer Accounts Expenses	38,965	15,947
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	50,899,289	56,259,233

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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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	1,506,578	1,018,269
168	(908) Customer Assistance Expenses	292,543	1,484,708
169	(909) Informational and Instructional Expenses	711,861	661,483
170	(910) Miscellaneous Customer Service and Informational Expenses	2,915	20,164
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	2,513,897	3,184,624
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	9,879	21,388
176	(913) Advertising Expenses	206	25,449
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	10,085	46,837
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	16,502,049	13,845,797
182	(921) Office Supplies and Expenses	3,432,900	4,016,078
183	(Less) (922) Administrative Expenses Transferred-Credit	2,388,983	2,319,676
184	(923) Outside Services Employed	13,561,064	17,807,924
185	(924) Property Insurance	3,010,064	2,054,623
186	(925) Injuries and Damages	3,732,154	3,413,764
187	(926) Employee Pensions and Benefits	21,317,346	13,054,219
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	113,326	123,136
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	1,273,244	781,462
192	(930.2) Miscellaneous General Expenses	1,352,127	1,034,429
193	(931) Rents	2,833,394	3,184,079
194	TOTAL Operation (Enter Total of lines 181 thru 193)	64,738,685	56,995,835
195	Maintenance		
196	(935) Maintenance of General Plant	4,725,579	4,910,803
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	69,464,264	61,906,638
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	1,221,652,871	1,476,677,021

FOOTNOTE DATA

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

Any amounts for 561.0 for both current and prior periods 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
Columbus Southern 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.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	AEP GENERATING COMPANY	RQ	AEG 3			
2	NATIONAL POWER COOPERATIVE INC	LF				
3	OHIO VALLEY ELECTRIC COMPANY	LF				
4	AEP SERVICE CORPORATION	OS	30			
5	AEP SERVICE CORPORATION	OS	20			
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					

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PURCHASED POWER (Account 555)
(Including power exchanges)

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	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
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PURCHASED POWER (Account 555)
(Including power exchanges)

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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 MARKETING INC	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					

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PURCHASED POWER (Account 555)
(Including power exchanges)

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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	MORGAN STANLEY CAPT.	OS				
10	NIPSCO ENERGY MANAGEMENT	OS				
11	NO CAROLINA MUNI PWR AGENCY	OS				
12	NRG POWER MARKETING INC.	OS				
13	OHIO ECONOMIC DEVELOPMENT RIDER	OS				
14	OLD DOMINION ELEC.	OS				
	Total					

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PURCHASED POWER (Account 555)
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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	OPPD ENERGY MARKETING	OS				
2	OTTER TAIL POWER COMPANY	OS				
3	PENNSYLVANIA ELECTRIC COMPANY	OS				
4	PJM ENVIRONMENTAL INFO SYS INC	OS				
5	PJM INTERCONNECTION	OS				
6	PP&L ENERGY PLUS CO.	OS				
7	PPL ENERGY SUPPLY, LLC	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	SOUTHERN MARYLAND ELEC COOP INC	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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	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
Columbus Southern 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	WPPI ENERGY	OS				
2	MISCELLANEOUS MWH ADJUSTMENTS	OS				
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 MegaWatt Hours Received (h)	POWER EXCHANGES MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
553,295			57,266,433	18,202,412		75,468,845	1
4,399			54,942	505,951		560,893	2
716,124				29,278,934		29,278,934	3
11,546,721				316,490,307		316,490,307	4
31,088				548,958		548,958	5
384				18,612		18,612	6
				185,804		185,804	7
1,101				43,971		43,971	8
2,583				86,197		86,197	9
				237,742		237,742	10
				-3,903		-3,903	11
				368,732		368,732	12
106				4,962		4,962	13
72				1,669		1,669	14
15,660,667			57,321,375	486,665,373	-10,149,519	533,837,229	

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 ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
				-441		-441	1
				5,786		5,786	2
				54,756		54,756	3
676				47,379		47,379	4
10,954				1,985,828		1,985,828	5
				-365		-365	6
7,312				320,319		320,319	7
608				17,486		17,486	8
2,384				67,755		67,755	9
				117		117	10
				54,592		54,592	11
198				11,562		11,562	12
				153,010		153,010	13
				-2,437		-2,437	14
15,660,667			57,321,375	486,665,373	-10,149,519	533,837,229	

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.
10,383				295,786		295,786	1
				6,264		6,264	2
				279		279	3
1,678				62,569		62,569	4
567,296				21,949,165		21,949,165	5
				32,187		32,187	6
18,024				1,344,571		1,344,571	7
				-39,468		-39,468	8
				64,351		64,351	9
				27,554		27,554	10
				25,873		25,873	11
				1,358		1,358	12
9,840				480,090		480,090	13
				59,348		59,348	14
15,660,667			57,321,375	486,665,373	-10,149,519	533,837,229	

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)	
779				22,823		22,823	1
				1,526		1,526	2
2,598				97,179		97,179	3
				62,429		62,429	4
				3,617		3,617	5
16,416				717,166		717,166	6
				18,386		18,386	7
525,837				18,541,331		18,541,331	8
				120,091		120,091	9
				-17,736		-17,736	10
18				735		735	11
2,213				90,088		90,088	12
					-10,149,519	-10,149,519	13
144				2,925		2,925	14
15,660,667			57,321,375	486,665,373	-10,149,519	533,837,229	

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.
106				2,843		2,843	1
				102,147		102,147	2
13,248				578,767		578,767	3
				1,397		1,397	4
1,522,123				63,351,768		63,351,768	5
38,335				1,422,381		1,422,381	6
241				13,453		13,453	7
32,888				1,968,328		1,968,328	8
123				3,238		3,238	9
				7,310		7,310	10
1,304				27,085		27,085	11
179				10,052		10,052	12
30,642				1,640,849		1,640,849	13
144				6,926		6,926	14
15,660,667			57,321,375	486,665,373	-10,149,519	533,837,229	

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.
306				11,972		11,972	1
144				9,577		9,577	2
439				20,890		20,890	3
				442,507		442,507	4
2,851				103,360		103,360	5
				3,444,750		3,444,750	6
431				91,299		91,299	7
1,098				34,724		34,724	8
				581,257		581,257	9
704				28,111		28,111	10
				39,641		39,641	11
				136,530		136,530	12
				39,604		39,604	13
				-147,159		-147,159	14
15,660,667			57,321,375	486,665,373	-10,149,519	533,837,229	

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)	
				35,584		35,584	1
-17,870							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
15,660,667			57,321,375	486,665,373	-10,149,519	533,837,229	

FOOTNOTE DATA

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

Associated Company.

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

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

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

CSPCo owns 4.3% of total equity in Ohio Valley Electric Corporation.

Schedule Page: 326 Line No.: 3 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.: 4 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: 326 Line No.: 5 Column: a

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

Schedule Page: 326.3 Line No.: 13 Column: l

The PUCO authorized CSP to defer any under recovery of purchased power expense equal to the difference between the ESP tariff rate and the rate paid by Ormet and Eramet 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

Detail of Misc. MWH Adjustments:

PJM Non-ECR	(6,913)	
AEG 1 & 2	481	
Bookouts/Options	2,351	
Fowler Wind Farm II	20	
MLR Purchases	(610,957)	
Spot Energy (PJM)	605,611	
Interupt-By-Thru	(2,451)	
MON POWER	(601)	
Pool Adjustment	(5,644)	*
PJM Losses	233	
	(17,870)	

* Pool Adjustment includes a prior year adjustment for June 2007 through July 2009 of (110,851)MWH.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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	RTO Formation Cost Recovery	Various	Various	OS
2	PJM Expansion Cost Recovery	Various	Various	OS
3	PJM Point to Point Trans Service	Various	Various	OLF
4	PJM Trans Owner Admin Revenues	Various	Various	OS
5	PJM Network Integ Trans Service	Various	Various	FNO
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
Columbus Southern 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)	
PJMOATT	Various	Various				1
PJMOATT	Various	Various				2
PJMOATT	Various	Various				3
PJMOATT	Various	Various				4
PJMOATT	Various	Various				5
PJMOATT	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
Columbus Southern 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.
		25,421	25,421	1
		128,043	128,043	2
2,289,666			2,289,666	3
		405,267	405,267	4
10,081,647			10,081,647	5
		548,377	548,377	6
				7
				8
				9
				10
				11
				12
				13
				14
				15
				16
				17
				18
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				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
12,371,313	**0**	**1,107,108**	**13,478,421**	

FOOTNOTE DATA

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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
Columbus Southern 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	AEP Sys Trans Agrmnt	FNS					51,308,780	51,308,780
2	PJM	OS					2,234,175	2,234,175
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL						53,542,955	53,542,955

FOOTNOTE DATA

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

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

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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	341,567
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	13,272
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	38,805
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	GridSMART	428,774
7	Associated Business Development	387,851
8	Affiliated Intercompany Billings	155,625
9	Unclaimed Funds Adjustment	-52,466
10	Various Chambers of Commerce	24,870
11	WINUP	12,364
12	Various Items Each < $5,000	1,465
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	1,352,127

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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			11,687,547		11,687,547
2	Steam Production Plant	41,998,016	2,676,327			44,674,343
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	9,033,531				9,033,531
7	Transmission Plant	12,769,913				12,769,913
8	Distribution Plant	59,968,342				59,968,342
9	Regional Transmission and Market Operation					
10	General Plant	3,176,943		2,778		3,179,721
11	Common Plant-Electric					
12	TOTAL	126,946,745	2,676,327	11,690,325		141,313,397

B. Basis for Amortization Charges

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

Line 10, Column D represents amortization of improvements to leased buildings over the life of the lease.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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 PRODUCTION						
13	311	46,290			2.35		
14	311.15	208,104			1.39		
15	312	448,449			2.17		
16	312.15	1,049,062			1.64		
17	314	116,466			2.71		
18	314.15	191,421			1.80		
19	315	39,877			2.06		
20	315.15	106,741			1.48		
21	316	17,430			2.71		
22	316.15	22,636			1.80		
23	TOTAL STEAM	2,246,476					
24							
25	OTHER GENERATION						
26	341	13,900			2.51		
27	342	7,516			1.97		
28	344	323,038			2.24		
29	345	45,862			2.41		
30	346	8,110			2.35		
31	TOTAL OTHER	398,426					
32							
33	TRANSMISSION						
34	352	47,768	50.00		2.10	R3	
35	352.15	380			2.50		
36	353	280,525	40.00		2.16	R2.5	
37	353.15	26,650	35.00		2.86	R2	
38	354	17,110	45.00		2.44	R3	
39	354.15	17,940			3.00		
40	355	78,887	45.00		2.44	S0.5	
41	355.15	3,156			3.00		
42	356	64,552	45.00		2.00	R2.5	
43	356.15	13,833			2.50		
44	357	10,498	45.00		2.27	S3	
45	358	19,063	30.00		3.33	R1.5	
46	TOTAL TRANSMISSION	580,362					
47							
48	DISTRIBUTION						
49	361	9,966	40.00		2.56	R2.5	
50	362	218,723	35.00		2.71	R1.5	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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	364	226,039	40.00		4.00	R1.5	
13	365	228,812	40.00		2.86	R2	
14	366	88,219			1.76		
15	367	362,782			2.67		
16	368	299,954	35.00		3.53	S0.5	
17	369	133,505			6.60		
18	370	80,376	35.00		4.00	R3	
19	370.16	530			14.29		
20	371	24,659	12.00		10.83	L2	
21	372	103			4.00		
22	373	12,422	25.00		5.40	L1	
23	TOTAL DISTRIBUTION	1,686,090					
24							
25	GENERAL PLANT						
26	390	54,173	45.00		2.44	R2.5	
27	391	4,578	20.00		4.50	L0	
28	391.15	488	15.00		5.94	R2	
29	393	302	30.00		2.94	L1.5	
30	394	10,225	30.00		3.17	L0.5	
31	395	632			6.67		
32	397	14,857	15.00		6.67	S1	
33	397.15	48	18.00		5.56	S1	
34	398	1,622	19.00		5.26	L1	
35	TOTAL GENERAL	86,925					
36	DEPRECIABLE SUM	4,998,279					
37							
38							
39							
40							
41							
42							
43							
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FOOTNOTE DATA

Schedule Page: 336.1 Line No.: 36 Column: b

(1) Subaccount .15 to all accounts indicate a segregation of facilities owned as tenants in common by Duke Energy, the Dayton Power and Light Company, and the respondent.

(2) Depreciable plant base in column B represent plant balances as of 11/30/2009

(3) Depreciation for 2009 was computed monthly by application of rates to prior month ending balances

(4) Depreciation expense calculation for Conesville Unit 3 and Picway Plant changed from annual rate times prior month plant balance to net plant divided by remaining estimated life.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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 forecasts.	118,692		118,692	
3					
4	Miscellaneous Expenses		-5,366	-5,366	
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
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35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	118,692	-5,366	113,326	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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	118,692					2
							3
Electric	928	-5,366					4
							5
							6
							7
							8
							9
							10
							11
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							40
							41
							42
							43
							44
							45
		113,326					46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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	ELECTRIC UTILITY RESEARCH,DEVELOPMENT &	
2	DEMONSTRATION PERFORMED INTERNALLY	
3		
4	A(1)b Generation: Fossil-Fuel Steam	8 items < $50,000
5		
6	A(1)e Generation: Unconventional Generation	DER Program Management
7		4 items < $50,000
8		
9	A(2) Transmission	6 items < $50,000
10		
11	A2(a) Transmission: Overhead	1 item < $50,000
12		
13	A(3) Distribution	4 items < $50,000
14		
15	A(4) Regional Transmission and Mkt Operation	1 item < $50,000
16		
17	A(5) Environment: (Other Than Equipme	Industrial Advisory Committee - Southern Company
18		7 items < $50,000
19		
20	A(6) Other:	Grid of the Future Test Bed
21		9 Items < $50,000
22		
23	A(7) TOTAL COST INCURRED INTERNALLY	
24		
25	ELECTRIC UTILITY RESEARCH, DEVELOPMENT &	
26	DEMONSTRATION PERFORMED EXTERNALLY	
27		
28	B(1) Research Support to Elec. Research	EPRI Research Portfolio
29	Council & Elec. Power Research Inst	EPRI Demo - IGCC
30		EPRI Environmental Controls
31		EPRI Environmental Science
32		62 items < $50,000
33		
34	B(4) Research Support to Others	8 items < $50,000
35		
36	B(5) TOTAL COSTS INCURRED EXTERNALLY	
37		
38		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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
					2
					3
49,274		506	49,274		4
					5
66,651		588	66,651		6
-31,129		506, 588	-31,129		7
					8
13,357		566	13,357		9
					10
911		566	911		11
					12
206		566, 588	206		13
					14
2,197		588	2,197		15
					16
57,079		506	57,079		17
16,563		506	16,563		18
					19
73,856		588	73,856		20
90,803		Various	90,803		21
					22
339,768			339,768		23
					24
					25
					26
					27
101,592		588	101,592		28
57,079		506	57,079		29
55,297		506	55,297		30
198,214		506	198,214		31
334,713		Various	334,713		32
					33
55,332		Various	55,332		34
					35
802,227			802,227		36
					37
					38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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	12,441,336		
4	Transmission	566,709		
5	Regional Market			
6	Distribution	11,666,605		
7	Customer Accounts	6,135,731		
8	Customer Service and Informational	491,840		
9	Sales			
10	Administrative and General	-41,965		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	31,260,256		
12	Maintenance			
13	Production	10,089,872		
14	Transmission	940,023		
15	Regional Market			
16	Distribution	10,817,345		
17	Administrative and General	1,414,419		
18	TOTAL Maintenance (Total of lines 13 thru 17)	23,261,659		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	22,531,208		
21	Transmission (Enter Total of lines 4 and 14)	1,506,732		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	22,483,950		
24	Customer Accounts (Transcribe from line 7)	6,135,731		
25	Customer Service and Informational (Transcribe from line 8)	491,840		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	1,372,454		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	54,521,915	2,916,106	57,438,021
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
Columbus Southern 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)	54,521,915	2,916,106	57,438,021
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	22,465,737	1,201,580	23,667,317
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	22,465,737	1,201,580	23,667,317
72	Plant Removal (By Utility Departments)			
73	Electric Plant	3,986,742	213,231	4,199,973
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	3,986,742	213,231	4,199,973
77	Other Accounts (Specify, provide details in footnote):			
78				
79	124 - Other Assets	112		112
80	151 - Fuel Stock	620		620
81	152 - Fuel Stock Undistributed	2,156,860		2,156,860
82	163 - Stores Expense Undistributed	2,464,310	-2,464,310	
83	182 - Other Regulatory Assets	305,090		305,090
84	184 - Clearing Accounts	1,866,607	-1,866,607	
85	185 - ODD Temporary Facilities	50,839		50,839
86	186 - Misc Deferred Debits	292,079		292,079
87	188 - Research & Development	3,791		3,791
88	421 - Misc Nonoperating Income	12,972		12,972
89	426 - Political Activities	5,517		5,517
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	7,158,797	-4,330,917	2,827,880
96	TOTAL SALARIES AND WAGES	88,133,191		88,133,191

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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
Columbus Southern 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)				11,730,634
3	Net Sales (Account 447)				(14,724,005)
4	Transmission Rights				(2,390,117)
5	Ancillary Services				1,388,577
6	Other Items (list separately)				
7	Congestion				3,128,182
8	Operating Reserves				801,203
9	Transmission Purchase Expense				(1,057)
10	Transmission Losses				5,747,603
11	Meter Corrections				23,482
12	Inadvertent				(68,085)
13	Miscellaneous				(2,350,233)
14					
15					
16					
17					
18					
19					
20					
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44					
45					
46	TOTAL				3,286,184

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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		633,229	.32/MWH	202,147
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)				633,229		202,147

FOOTNOTE DATA

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

Represents Company's MLR share of AEP System 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
Columbus Southern 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

Columbus Southern 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
Columbus Southern 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
Columbus Southern 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)	20,673,469
3	Steam	11,370,453	23	Requirements Sales for Resale (See instruction 4, page 311.)	498,182
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	5,363,938
5	Hydro-Conventional		25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
7	Other	641,627	27	Total Energy Losses	1,137,158
8	Less Energy for Pumping		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	27,672,747
9	Net Generation (Enter Total of lines 3 through 8)	12,012,080			
10	Purchases	15,660,667			
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)	27,672,747			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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	2,601,802	372,602	3,934	15	2000
30	February	2,224,814	375,897	3,710	5	0800
31	March	2,267,921	445,680	3,560	2	2000
32	April	2,082,763	404,807	3,160	27	1600
33	May	2,085,435	365,408	3,357	27	1600
34	June	2,543,282	620,141	4,209	25	1600
35	July	2,434,453	517,103	3,789	16	1600
36	August	2,735,715	710,959	4,067	17	1500
37	September	2,188,395	478,349	3,281	15	1600
38	October	2,042,933	383,356	2,737	14	1900
39	November	1,996,978	357,646	2,930	30	2000
40	December	2,468,256	499,237	3,510	10	1900
41	TOTAL	27,672,747	5,531,185			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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: *CONESVILLE 3, 5 & 6* (b)			Plant Name: *PICWAY* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	STEAM			STEAM		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	FULL OUTDOOR			OUTDOOR BOILER		
3	Year Originally Constructed	1957			1926		
4	Year Last Unit was Installed	1978			1955		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	1070.00			106.25		
6	Net Peak Demand on Plant - MW (60 minutes)	953			101		
7	Plant Hours Connected to Load	7155			2185		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	965			100		
10	When Limited by Condenser Water	965			95		
11	Average Number of Employees	327			30		
12	Net Generation, Exclusive of Plant Use - KWh	4434404000			119613000		
13	Cost of Plant: Land and Land Rights	236497			125244		
14	Structures and Improvements	39878666			6629294		
15	Equipment Costs	620069306			34912015		
16	Asset Retirement Costs	26128808			4571296		
17	Total Cost	686313277			46237849		
18	Cost per KW of Installed Capacity (line 17/5) Including	641.4143			435.1798		
19	Production Expenses: Oper, Supv, & Engr	1786807			986998		
20	Fuel	120475563			3839162		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	13811109			639083		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	1230860			365251		
26	Misc Steam (or Nuclear) Power Expenses	10919883			997383		
27	Rents	0			0		
28	Allowances	2842265			375646		
29	Maintenance Supervision and Engineering	371677			331157		
30	Maintenance of Structures	898136			661877		
31	Maintenance of Boiler (or reactor) Plant	19180160			1932351		
32	Maintenance of Electric Plant	4506838			689474		
33	Maintenance of Misc Steam (or Nuclear) Plant	473555			142698		
34	Total Production Expenses	176496853			10961080		
35	Expenses per Net KWh	0.0398			0.0916		
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	2020283	11198	0	47622	2594	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	11489	138379	0	11481	138610	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	54.582	76.284	0.000	80.857	74.070	0.000
41	Average Cost of Fuel per Unit Burned	53.590	88.675	0.000	74.348	72.291	0.000
42	Average Cost of Fuel Burned per Million BTU	2.332	15.257	0.000	3.238	12.418	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.024	0.000	0.000	0.030	0.000	0.000
44	Average BTU per KWh Net Generation	10483.000	0.000	0.000	9263.000	0.000	0.000

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Columbus Southern 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: *BECKJORD - CSP SHARE* (b)			Plant Name: *STUART - CSP SHARE* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	STEAM			STEAM		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	CONVENTIONAL			SEMI-OUTDOOR		
3	Year Originally Constructed	1969			1970		
4	Year Last Unit was Installed	-			1974		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	57.60			634.61		
6	Net Peak Demand on Plant - MW (60 minutes)	59			609		
7	Plant Hours Connected to Load	7585			8094		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	53			600		
10	When Limited by Condenser Water	52			600		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	280882000			3856273000		
13	Cost of Plant: Land and Land Rights	175499			676940		
14	Structures and Improvements	1296835			23621620		
15	Equipment Costs	17702481			473881357		
16	Asset Retirement Costs	225419			1050643		
17	Total Cost	19400234			499230560		
18	Cost per KW of Installed Capacity (line 17/5) Including	336.8096			786.6730		
19	Production Expenses: Oper, Supv, & Engr	144312			1827305		
20	Fuel	5143121			97071209		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	203452			4426226		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	1241			387286		
26	Misc Steam (or Nuclear) Power Expenses	562172			3363491		
27	Rents	0			-139		
28	Allowances	373538			2225741		
29	Maintenance Supervision and Engineering	165175			467581		
30	Maintenance of Structures	38680			628337		
31	Maintenance of Boiler (or reactor) Plant	461250			11807673		
32	Maintenance of Electric Plant	114970			1320756		
33	Maintenance of Misc Steam (or Nuclear) Plant	53220			0		
34	Total Production Expenses	7261131			123525466		
35	Expenses per Net KWh	0.0259			0.0320		
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	123515	547	0	1705585	14326	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	11500	137385	0	11101	137400	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	60.527	59.813	0.000	53.968	76.939	0.000
41	Average Cost of Fuel per Unit Burned	62.364	85.002	0.000	53.757	75.786	0.000
42	Average Cost of Fuel Burned per Million BTU	2.711	14.731	0.000	2.421	13.133	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.027	0.000	0.000	0.024	0.000	0.000
44	Average BTU per KWh Net Generation	10114.000	0.000	0.000	9841.000	0.000	0.000

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Columbus Southern 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

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Columbus Southern 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: *CONESVILLE 4 - TOTAL* (d)			Plant Name: *CONES. 4 - CSP SHARE* (e)			Plant Name: *ZIMMER - CSP SHARE* (f)			Line No.
STEAM			STEAM			STEAM			1
CONVENTIONAL			CONVENTIONAL			CONVENTIONAL			2
1973			1973			1991			3
-			-			-			4
841.50			366.05			362.11			5
784			370			341			6
3231			3231			6041			7
0			0			0			8
780			337			333			9
780			337			330			10
0			0			0			11
1755580000			807380000			1871901000			12
74828			32550			5959406			13
37161246			16165142			166942014			14
652905859			284014049			595435468			15
997665			433984			396956			16
691139598			300645725			768733844			17
821.3186			821.3242			2122.9291			18
0			684973			949888			19
0			23066684			38537463			20
0			0			0			21
0			1402543			6927204			22
0			0			0			23
0			0			0			24
0			52638			254817			25
0			5870787			1372942			26
0			0			0			27
0			972347			593252			28
0			154618			720907			29
0			314942			822858			30
0			7889647			7144211			31
0			2626355			1001705			32
0			607788			1403199			33
0			43643322			59728446			34
0.0000			0.0541			0.0319			35
Coal	Oil		Coal	Oil		Coal	Oil		36
Tons	Barrels		Tons	Barrels		Tons	Barrels		37
805292	7206	0	367098	3135	0	782638	12043	0	38
11621	138639	0	11622	138639	0	11861	137552	0	39
62.503	74.923	0.000	62.396	74.923	0.000	46.616	730166.000	0.000	40
58.977	87.899	0.000	59.008	87.899	0.000	47.184	92.427	0.000	41
2.538	15.096	0.000	2.539	15.096	0.000	1.989	15.999	0.000	42
0.027	0.000	0.000	0.027	0.000	0.000	0.020	0.000	0.000	43
10685.000	0.000	0.000	10591.000	0.000	0.000	9956.000	0.000	0.000	44

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Columbus Southern 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: *WATERFORD* (d)			Plant Name: *DARBY* (e)			Plant Name: (f)			Line No.
COMBINED CYCLE			GAS TURBINE						1
OUTDOOR HRSG			NO BOILER						2
2003			2001						3
2003			2002						4
917.00			650.00			0.00			5
836			470			0			6
1297			44			0			7
0			0			0			8
840			507			0			9
810			438			0			10
24			0			0			11
627595000			14032000			0			12
3000000			713584			0			13
10575252			3329343			0			14
198392124			186475066			0			15
0			0			0			16
211967376			190517993			0			17
231.1531			293.1046			0.0000			18
1127003			791614			0			19
17519280			1142094			0			20
0			0			0			21
38975			13566			0			22
0			0			0			23
0			0			0			24
0			130583			0			25
2879911			782873			0			26
0			32341			0			27
21546			9638			0			28
146611			142499			0			29
7304			5633			0			30
3277080			1203			0			31
405489			743609			0			32
0			160655			0			33
25423199			3956308			0			34
0.0405			0.2819			0.0000			35
Gas			Gas						36
MCFs			MCFs						37
4580984	0	0	172979	0	0	0	0	0	38
1024000	0	0	1017000	0	0	0	0	0	39
3.767	0.000	0.000	6.479	0.000	0.000	0.000	0.000	0.000	40
3.799	0.000	0.000	6.479	0.000	0.000	0.000	0.000	0.000	41
3.709	0.000	0.000	6.371	0.000	0.000	0.000	0.000	0.000	42
0.027	0.000	0.000	0.080	0.000	0.000	0.000	0.000	0.000	43
7474.000	0.000	0.000	12537.000	0.000	0.000	0.000	0.000	0.000	44

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Columbus Southern 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: d

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

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

Conesville Unit #4 - CSP Share: See footnote above.

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

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

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

Deferred fuel expenses totalling ($37,545,778) are not included in the fuel totals that are broken down by generating plant.

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

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

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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. 0 Plant Name: (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)		
2	Plant Construction type (Conventional or Outdoor)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total installed cap (Gen name plate Rating in MW)	0.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	0
7	Plant Hours Connect to Load	0	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	0	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	0	0
13	Cost of Plant		
14	Land and Land Rights	0	0
15	Structures and Improvements	0	0
16	Reservoirs, Dams, and Waterways	0	0
17	Equipment Costs	0	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	0	0
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	0	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	0	0
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Hydraulic Plant	0	0
34	Total Production Expenses (total 23 thru 33)	0	0
35	Expenses per net KWh	0.0000	0.0000

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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
Columbus Southern 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
Columbus Southern 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
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			10
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			36
			37
			38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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						
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46						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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
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						9
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						11
						12
						13
						14
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						44
						45
						46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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	FULLY OWNED TRANS							
2	BEATTY	HAYDEN	345.00	345.00	1			1
3	9032 BEATTY	HAYDEN	345.00	345.00	3	17.00		1
4	9034 CONESVILLE	CORRIDOR	345.00	345.00	3	54.00		1
5	C633 POINT N	STR. 96-1	345.00	345.00	1,3	4.24		1
6	HAYDEN	HYATT	345.00	345.00	1			1
7	HAYDEN	HYATT	345.00	345.00	2			1
8	9037 HAYDEN	HYATT	345.00	345.00	3	12.00		1
9	9038 HAYDEN	ROBERTS	345.00	345.00	1	11.53		1
10	9039 POINT Z	CORRIDOR	345.00	345.00	3	13.00		1
11	C613 KIRK EXT #1 (NORTH)		345.00	345.00	1	0.25		1
12	C614 KIRK EXT #2 (SOUTH)		345.00	345.00	1	0.25		1
13	8790 DAVIDSON	DUBLIN	138.00	138.00	4	3.16		1
14	C710 DUBLIN	SAWMILL	138.00	138.00	1	6.40		1
15	C795 KIMBERLY		138.00	138.00	1	0.56		2
16	C796 DON MARQUIS LOOP		138.00	138.00	1	6.60		1
17	C798 DON MARQUIS LOOP		138.00	138.00	1	0.65		1
18	C799 GREIF EXTENSION		138.00	138.00	4	0.66		2
19	C800 Lick	JACKSON	138.00	138.00				
20	C850 WILLOW ISLAND	MILL CREEK	138.00	138.00	1	9.14		1
21	C851 MILL CREEK	RIVERVIEW	138.00	138.00	1	10.80		1
22	C852 RIVERVIEW	CORNER	138.00	138.00	1	7.09		1
23	C853 CORNER	SHELL	138.00	138.00	1	2.13		1
24	C854 PARKERSBURG	CORNER	138.00	138.00	1	7.67		1
25	C855 MUSKINGUM	CORNER	138.00	138.00	1	15.79		1
26	C856 BELMONT	RIVERVIEW	138.00	138.00	1	0.86		1
27	C857 WASHINGTON	CORNER	138.00	138.00	1	6.51		1
28	C858 RIVERVIEW	ELKEM METALS	138.00	138.00	1	0.80		1
29	COMMONLY OWNED: (A)							
30	9001 BECKJORD	PIERCE	345.00	345.00	3			1
31	9002 PIERCE	FOSTER	345.00	345.00	3	24.00		1
32	SUGARCREEK	GREENE	345.00	345.00	3	8.00		1
33	9003 SUGARCREEK	GREENE	345.00	345.00	2			1
34	9006 GREENE	BEATTY	345.00	345.00	3	49.00		1
35	9007 MARQUIS	POINT X	345.00	345.00	3	46.00		1
36					TOTAL	2,212.90	163.65	217

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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	STUART	GREENE	345.00	345.00	3	79.00		1
2	STUART	GREENE	345.00	345.00	2	1.00		1
3	9009 STUART	GREENE	345.00	345.00	3	1.00		1
4	9010 STUART	POINT M-KILLEN	345.00	345.00	3	13.00		1
5	STUART	FOSTER	345.00	345.00	3	55.00		1
6	9011 STUART	FOSTER	345.00	345.00	3	1.00	3.00	1
7	9024 FOSTER	SUGARCREEK	345.00	345.00	3	27.00		1
8	9041 STUART	ZIMMER	345.00	345.00	3	35.00		1
9	9044 ZIMMER	PORT UNION	345.00	345.00	3	10.00		1
10	9049 KILLEN-POINT O	MARQUIS	345.00	345.00				
11	POINT O-KILLEN	MARQUIS	345.00	345.00	3	32.00		1
12	POINT Y	BEATTY	345.00	345.00	3	15.00		1
13	9742 POINT Y	BEATTY	345.00	345.00	3		4.00	1
14	COMMONLY OWNED: (B)							
15	9031 BEATTY	BIXBY	345.00	345.00	3	13.00		1
16	STUART	TOWER 2	345.00	345.00	3			1
17	9042 TOWER 2	POINT Y	345.00	345.00	3	75.00		1
18	CONESVILLE	TOWER 71	345.00	345.00	2	51.00		1
19	9043 TOWER 71	BIXBY	345.00	345.00	3		15.00	1
20	POINT X	TOWER 27	345.00	345.00	3	17.00		1
21	9707 TOWER 27	BIXBY	345.00	345.00	3		9.00	1
22	COMMONLY OWNED: (C)							
23	9040 CONESVILLE	POINT Z	345.00	345.00	3	57.00		1
24	COMMONLY OWNED: (D)							
25	POINT Z	HYATT	345.00	345.00	3	9.00		1
26	POINT Z	HYATT	345.00	345.00	1	2.00		1
27	9740 POINT Z	HYATT	345.00	345.00	2			1
28	COMMONLY OWNED: (E)							
29	STUART	ZIMMER	345.00	345.00	3	1.00		1
30	9045 ZIMMER-SILVER	RED BANK	345.00	345.00	3	33.00	2.00	1
31	9145 ZIMMER-SILVER	RED BANK	345.00	345.00	3			1
32	9046 RED BANK	TERMINAL	345.00	345.00	3	7.00		1
33	9053 ZIMMER	PIERCE	345.00	345.00	3	1.00	36.00	1
34	ROBERTS	BETHEL	138.00	138.00	1			2
35	8001 ROBERTS	BETHEL	138.00	138.00	3	5.00		2
36					TOTAL	2,212.90	163.65	217

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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	ROBERTS	KENNY	138.00	138.00	1	1.00		1
2	8002 ROBERTS	KENNY	138.00	138.00	4	3.00		1
3	C789 BEAVER 138KV		138.00	138.00				
4	BETHEL	LINWORTH	138.00	138.00	3		3.00	1
5	8004 BETHEL	LINWORTH	138.00	138.00	1	2.00		1
6	8005 PICWAY	HARRISON	138.00	138.00	3	1.00		1
7	8008 GROVES	BEXLEY	138.00	138.00	1	4.00		1
8	8009 BEXLEY	ST. CLAIR	138.00	138.00	1	4.00		1
9	BIXBY	LSII	138.00	138.00	1	1.00	2.00	1
10	BIXBY	LSII	138.00	138.00	2	2.00		1
11	8010 BIXBY	LSII	138.00	138.00	3			1
12	BIXBY	W. LANCASTER	138.00	138.00	2	18.00		1
13	BIXBY	W. LANCASTER	138.00	138.00	2			1
14	8011 BIXBY	W. LANCASTER	138.00	138.00	2	1.00		1
15	POSTON	ROSS	138.00	138.00	2	42.00		1
16	8012 POSTON	ROSS	138.00	138.00	3	1.00		1
17	8013 ROSS	DELANO	138.00	138.00	2	5.00		1
18	8013 ROSS	DELANO	138.00	138.00	1	0.32		1
19	CIRCLEVILLE	HARRISON	138.00	138.00	2	14.00		1
20	8014 CIRCLEVILLE	HARRISON	138.00	138.00	3	1.00		1
21	LSII	MARION	138.00	138.00	1	2.17		1
22	8015 LSII	MARION	138.00	138.00	3	3.00		1
23	8016 MARION	CANAL	138.00	138.00	4	4.00		1
24	8017 ST CLAIR	CLINTON	138.00	138.00	4	4.00		1
25	HARRISON	MARION	138.00	138.00	2	7.00		1
26	8018 HARRISON	MARION	138.00	138.00	3		3.00	1
27	8019 BIXBY	GROVES-ASTOR	138.00	138.00	1	13.00		1
28	8020 POSTON	HARRISON	138.00	138.00	2	54.00		1
29	8021 BEATTY	WILSON (EAST)	138.00	138.00	3	7.00	1.00	1
30	BEATTY	WILSON (WEST)	138.00	138.00	3		1.00	2
31	8022 BEATTY	WILSON (WEST)	138.00	138.00	3		9.00	1
32	8023 WAVERLY	SARGENTS	138.00	138.00	2	16.00		1
33	WAVERLY	ADAMS-SEAMAN	138.00	138.00	2	25.00		1
34	8024 WAVERLY	ADAMS-SEAMAN	138.00	138.00	2	11.00		1
35	CIRCLEVILLE	SCIPPO	138.00	138.00	2	2.00		1
36					TOTAL	2,212.90	163.65	217

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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	8025 CIRCLEVILLE	SCIPPO	138.00	138.00	1	1.00		1
2	POSTON	LICK	138.00	138.00	1			1
3	8026 POSTON	LICK	138.00	138.00	3	35.00		1
4	WAVERLY	LICK	138.00	138.00	1			1
5	WAVERLY	LICK	138.00	138.00	2	16.00		1
6	8027 WAVERLY	LICK	138.00	138.00	3	11.00		1
7	MORSE	GENOA-KARL	138.00	138.00	3	4.00		1
8	8028 MORSE	GENOA-KARL	138.00	138.00	1	5.00		1
9	MORSE	GENOA-KARL	138.00	138.00	2	2.00		1
10	8029 OSU	HESS	138.00	138.00	4	1.00		1
11	8030 WILSON	FIFTH-HESS	138.00	138.00	3	3.00		1
12	WILSON	FIFTH-HESS	138.00	138.00	4	2.00		1
13	WILSON	ROBERTS	138.00	138.00	3	5.00		1
14	8031 WILSON	ROBERTS	138.00	138.00	1			1
15	WILSON	ROBERTS	138.00	138.00	1	1.00		2
16	BIXBY	BUCKEYE STEEL	138.00	138.00	3	3.00	1.00	1
17	BIXBY	BUCKEYE STEEL	138.00	138.00	2	2.00		1
18	8032 BIXBY	BUCKEYE STEEL	138.00	138.00	1	1.17		1
19	8033 GAY	VINE	138.00	138.00	4	2.00		1
20	EAST BROAD	GAHANNA	138.00	138.00	1	0.03	1.03	1
21	8034 EAST BROAD	GAHANNA	138.00	138.00	2	1.00		1
22	EAST BROAD	GAHANNA	138.00	138.00	2	3.00		1
23	8035 HYATT	SAWMILL	138.00	138.00	1			1
24	HYATT	SAWMILL	138.00	138.00	2	5.00		1
25	8036 GAHANNA	MORSE	138.00	138.00	2	5.00		1
26	GAHANNA	MORSE	138.00	138.00	2			1
27	CORRIDOR	MORSE-BLENDON	138.00	138.00	3		7.00	1
28	8037 CORRIDOR	MORSE-BLENDON	138.00	138.00	1	1.00		2
29	8038 CORRIDOR	MORSE	138.00	138.00	3	7.00		1
30	8039 KIRK	EAST BROAD	138.00	138.00	3	10.00		1
31	8040 KIRK	EAST BROAD	138.00	138.00	3		10.00	1
32	8041 CANAL	MOUND	138.00	138.00	4	2.00		1
33	8043 CONESVILLE	TRENT	138.00	138.00	3	52.00		1
34	CONESVILLE	TRENT	138.00	138.00	1			1
35	TRENT	DELAWARE	138.00	138.00	3	13.00		1
36					TOTAL	2,212.90	163.65	217

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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.
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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	8044 TRENT	DELAWARE	138.00	138.00	1			1
2	8046 ST. CLAIR	MIFFLIN STELZER	138.00	138.00	1	7.00		1
3	KENNY	KARL	138.00	138.00	3	1.00		1
4	KENNY	KARL	138.00	138.00	3	3.00		1
5	8047 KENNY	KARL	138.00	138.00	4	3.00		1
6	MORSE	CLINTON	138.00	138.00	3		5.00	1
7	MORSE	CLINTON	138.00	138.00	3		3.00	1
8	8048 MORSE	HUNTLEY-CLINTON	138.00	138.00	3	3.00		1
9	BIXBY	GROVES	138.00	138.00	3	3.00		2
10	BIXBY	GROVES	138.00	138.00	1	1.00		2
11	BIXBY	GROVES	138.00	138.00	3			1
12	8049 BIXBY	GROVES	138.00	138.00	1			1
13	POSTON	STROUDS	138.00	138.00	1			1
14	8051 POSTON	STROUDS	138.00	138.00	2	7.00		1
15	8052 HYATT	DELAWARE	138.00	138.00	2	4.00		1
16	8053 BEATTY	CANAL	138.00	138.00	1	11.34	2.00	1
17	8055 CONESVILLE	OHIO CENTRAL	138.00	138.00	2	12.00		1
18	8056 EAST BROAD	ASTOR	138.00	138.00	1	3.00		1
19	8057 HARRISON	BEATTY	138.00	138.00	1,3	8.57	0.12	1
20	8058 HARRISON	S CENTRAL REA	138.00	138.00	1			1
21	8060 BEATTY	MCCOMB	138.00	138.00	1	2.00	3.00	1
22	MORSE	STELZER	138.00	138.00	4	2.00		1
23	8061 MORSE	STELZER	138.00	138.00	1	2.00		1
24	8062 HUNTLEY	LINWORTH	138.00	138.00	1	3.23	1.00	1
25	8065 HYATT	GENOA	138.00	138.00	1	5.00	9.00	1
26	BUCKEYE STEEL	GAY	138.00	138.00	1	3.00		1
27	8066 BUCKEYE STEEL	GAY	138.00	138.00	4	1.00		1
28	POSTON	ELLIOT-DEXTER	138.00	138.00	1			1
29	8067 POSTON	ELLIOT-DEXTER	138.00	138.00	2	7.00		1
30	8068 HYATT	HUNTLEY	138.00	138.00	1	12.00		1
31	LICK	ADDISON	138.00	138.00	2	29.00		1
32	8069 LICK	ADDISON	138.00	138.00	1			1
33	SCIPPO	SCIOTO TRAIL - DUPONT	138.00	138.00	1	1.00		1
34	SCIPPO	SCIOTO TRAIL - DUPONT	138.00	138.00	2		1.00	1
35	8070 SCIPPO	SCIOTO TRAIL-DUPONT	138.00	138.00	2	1.00		1
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TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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Line No.	DESIGNATION		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	DELANO	SCIOTO TRAIL	138.00	138.00	2	11.00		1
2	8071 DELANO	SCIOTO TRAIL	138.00	138.00	1	1.00		1
3	8071 DELANO	SCIOTO TRAIL	138.00	138.00	2	0.31		1
4	SAWMILL	BETHEL	138.00	138.00	1			1
5	8072 SAWMILL	BETHEL	138.00	138.00	3	5.00		1
6	8074 SCIPPO	HARGUS	138.00	138.00	1	1.00		1
7	8075 MOUND	ST. CLAIR	138.00	138.00	4	2.00		1
8	WAVERLY	MULBERRY	138.00	138.00	1	2.00		1
9	8077 WAVERLY	MULBERRY	138.00	138.00	1	2.06		1
10	8078 MCCOMB	SULLIVANT-GAY	138.00	138.00		8.00		2
11	MULBERRY	ROSS	138.00	138.00	1		2.00	1
12	MULBERRY	ROSS	138.00	138.00	2	3.00		1
13	8079 MULBERRY	ROSS	138.00	138.00	1	1.00		1
14	8080 EAST BROAD	BEXLEY	138.00	138.00	1	6.00		1
15	8081 HYATT	ROSS	138.00	138.00	1	1.00		1
16	8082 CORRIDOR	GENOA	138.00	138.00	1			1
17	8083 CORRIDOR	GAHANNA	138.00	138.00	1	1.00		1
18	KIRK	W. MILLERSPORT	138.00	138.00	3		8.00	1
19	KIRK	W. MILLERSPORT	138.00	138.00	3			1
20	CONESVILLE	KIRK	138.00	138.00	2			1
21	CONESVILLE	KIRK	138.00	138.00	3	38.00		2
22	8086 CONESVILLE	KIRK	138.00	138.00	3	8.00		1
23	8088 HESS	VINE	138.00	138.00	4	2.00		1
24	8092 VINE	CITY OF COLUMBUS EAST	138.00	138.00	1	1.28		1
25	POSTON	W. LANCASTER	138.00	138.00	2	12.00		1
26	POSTON	W. LANCASTER	138.00	138.00	1			1
27	8096 POSTON	W. LANCASTER	138.00	138.00	2	23.00		1
28	8098 VINE	CITY OF COLUMBUS WEST	138.00	138.00	1	1.00		1
29	ST. CLAIR	VINE	138.00	138.00	1	1.00		1
30	8099 ST. CLAIR	VINE	138.00	138.00	4	1.00		1
31	8102 CLINTON	OSU	138.00	138.00	4	4.00		1
32	8105 DAVIDSON RD	ROBERTS-BETHEL	138.00	138.00	1			2
33	8129 OSU	HESS	138.00	138.00	4	1.00		1
34	8712 SCIPPO	EAST SCIPPO	138.00	138.00				
35	EAST BROAD	BEXLEY	138.00	138.00	2			1
36					TOTAL	2,212.90	163.65	217

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

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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	8788 FISHER 138KV		138.00	138.00	3	0.42		1
2	C792 CLAYBURNE	KENWORTH	138.00	138.00	1	0.32		1
3	C793 DELANO	KENWORTH	138.00	138.00	1	0.31		1
4	C794 BOLTON EXTENSION		138.00	138.00				
5	COMMONLY OWNED: (F)							
6	C633A BIXBY	POINT N	345.00	345.00	3	14.81		1
7	C633B KIRK	CORRIDOR	345.00	345.00	2	18.38		1
8	TRANSMISSION LINES	LESS THAN 132 KV				607.09	22.50	
9								
10	EXPENSES 345KV LINES							
11	EXPENSES 138KV LINES							
12	EXPENSES <132KV LINES							
13								
14								
15								
16								
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21								
22								
23								
24								
25								
26								
27								
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32								
33								
34								
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36					TOTAL	2,212.90	163.65	217

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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)	
								1
2-954 ACSR								2
2-954 ACSR	1,194,611	3,101,280	4,295,891					3
2-954 ACSR	742,088	4,966,382	5,708,470					4
2-954 ACSR	70,173	4,033,425	4,103,598					5
2-954 ACSR								6
2-954 ACSR								7
2-954 ACSR	835,964	1,916,457	2,752,421					8
2-954 ACSR	1,238,509	4,809,603	6,048,112					9
2-954 ACSR	789,723	3,903,904	4,693,627					10
636 ACSR 26/7		68,482	68,482					11
636 ACSR 26/7		67,644	67,644					12
2000 CU KCM		7,120,559	7,120,559					13
636 ACSR 26/7	254,401	1,251,386	1,505,787					14
636 ACSR 26/7	21,083	716,838	737,921					15
1033.5 KCM		9,690,885	9,690,885					16
1033.5 KCM		1,112,156	1,112,156					17
2000 kcm CU		9,807	9,807					18
								19
954 ACSR 45/7	141,721	877,711	1,019,432					20
954 ACSR 45/7	409,734	1,494,023	1,903,757					21
954 ACSR 45/7	460,764	1,023,764	1,484,527					22
336.4 ACSR 26/7	13,024	74,763	87,787					23
336.4&954 ACSR	68,318	329,836	398,154					24
556.5 ACSR 26/7	206,006	349,959	555,965					25
954 ACSR 45/7	32,224	223,438	255,661					26
954 ACSR 45/7	400,377	729,440	1,129,817					27
954 ACSR 45/7	86,869	939,648	1,026,516					28
								29
1414 ACSR	14,534	49,229	63,763					30
2-1024 ACAR	341,949	829,458	1,171,407					31
2-1024 ACAR								32
2-1024 ACAR								33
2-1024 ACAR	407,288	1,348,252	1,755,540					34
2-983 ACAR	224,274	1,371,171	1,595,445					35
	35,991,548	219,547,198	255,538,743	11,475	3,363,663		3,375,138	36

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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)	
2-1024 ACAR								1
2-1024 ACAR								2
2-1024 ACAR	457,134	2,262,033	2,719,167					3
2-983 ACAR	110,255	1,559,205	1,669,460					4
2-1024 ACAR								5
2-1024 ACAR	380,541	1,547,728	1,928,269					6
2-1024 ACAR	17,085		17,085					7
2-954 ACSR	262,436	1,428,384	1,690,820					8
2-954 ACSR	292,501	1,255,302	1,547,803					9
		115,415	115,415					10
2-983 ACAR								11
2-983 ACAR								12
2-983 ACAR	106,814	569,305	676,119					13
								14
2-954 ACSR	238,833	747,276	986,109					15
2-954 ACSR								16
2-954 ACSR	679,660	2,141,019	2,820,679					17
2-954 ACSR								18
2-954 ACSR	360,944	1,574,980	1,935,924					19
2-954 ACSR								20
2-954 ACSR	213,385	563,492	776,877					21
								22
2-954 ACSR	1,514,424	5,630,711	7,145,135					23
								24
2-954 ACSR								25
2-954 ACSR								26
2-954 ACSR	613,989	2,097,710	2,711,699					27
								28
2-954 ACSR								29
2-954 ACSR	46,141	3,333,699	3,379,840					30
2-954 ACSR	261,902	3,054,661	3,316,563					31
2-954 ACSR	232,956	2,023,424	2,256,380					32
2-954 ACSR	153,013	531,322	684,335					33
636 ACSR								34
636 ACSR	154,413	839,323	993,736					35
	35,991,548	219,547,198	255,538,743	11,475	3,363,663		3,375,138	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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)
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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
2500 ALUM	15,618	2,565,158	2,580,776					2
0	1,623		1,623					3
636 ACSR								4
636 AA	30,989	271,745	302,734					5
636 ACSR		5,881	5,881					6
636 ACSR	275,683	430,554	706,237					7
636 AA	94,264	611,160	705,424					8
636 ACSR								9
636 ACSR								10
636 ACSR	50,964	3,079,914	3,130,877					11
4/O CWC								12
954 ACSR								13
636 ACSR	112,126	1,250,821	1,362,947					14
636 ACSR								15
636 ACSR	303,062	1,598,592	1,901,654					16
336.4 ACSR	25,566	271,709	297,275					17
556.5 ACSR 18/1								18
336.4 ACSR								19
636 ACSR	156,176	1,351,513	1,507,689					20
636 ACSR								21
636 ACSR	289,360	1,781,791	2,071,151					22
600 CU PIPT		727,982	727,982					23
600 CU PIPT	2	637,129	637,131					24
636 ACSR								25
636 ACSR	51,703	497,455	549,159					26
636 AA	636,315	1,682,366	2,318,682					27
636 ACSR	692,511	1,220,285	1,912,796					28
636 ACSR	108,649	529,978	638,627					29
636 ACSR								30
636 ACSR	164,110	647,056	811,166					31
636 ACSR	219,295	1,407,743	1,627,038					32
336.4 ACSR								33
636 ACSR	376,920	2,287,430	2,664,350					34
336.4 ACSR								35
	35,991,548	219,547,198	255,538,743	11,475	3,363,663		3,375,138	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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TRANSMISSION LINE STATISTICS (Continued)

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9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
636 ACSR	23,380	688,628	712,008					1
636 ACSR								2
636 ACSR	665,085	1,159,743	1,824,828					3
636 ACSR								4
636 ACSR								5
636 ACSR	1,226,980	3,994,566	5,221,546					6
1272 ACSR								7
636 ACSR	231,180	855,108	1,086,288					8
600 CU PIPT								9
636 ACSR	69,573	2,041,637	2,111,210					10
600 CU PIPT	97,260	1,025,843	1,123,103					11
636 ACSR								12
636 ACSR								13
636 ACSR	546,274	2,368,946	2,915,220					14
636 ACSR								15
636 ACSR								16
636 AA								17
1250 CU PIPT	11,703	909,031	920,734					18
954 ACSR	64,446	564,718	629,164					19
636 AA								20
336.4 ACSR	103,917	464,894	568,811					21
636 ACSR								22
636 ACSR	104,014	716,135	820,149					23
336.4 ACSR								24
636 ACSR	43,113	3,839,996	3,883,109					25
1272 ACSR								26
1272 ACSR								27
1272 ACSR		486,015	486,015					28
1272 ACSR	365,837	379,394	745,231					29
1272 ACSR	312,452	676,797	989,249					30
600 CU PIPT	786	265,320	266,106					31
1272 ACSR	18,282	1,205,012	1,223,294					32
1272 ACSR	776,375	2,479,633	3,256,008					33
1272 ACSR								34
1272 ACSR								35
	35,991,548	219,547,198	255,538,743	11,475	3,363,663		3,375,138	36

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

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)	
1272 ACSR	351,919	910,978	1,262,897					1
636 AA	86,821	964,763	1,051,584					2
1272 ACSR								3
336.4 ACSR								4
2500 ALUM	32,810	2,172,523	2,205,333					5
1272 ACSR								6
636 ACSR								7
636 AA	12,669	306,092	318,761					8
636 ACSR								9
636 ACSR								10
1272 ACSR								11
336.4 ACSR	515,448	633,338	1,148,786					12
1272 KCM								13
636 ACSR	110,523	572,841	683,364					14
636 ACSR	43,940	416,697	460,637					15
636 AA	145,824	1,330,791	1,476,614					16
636 ACSR	180,778	1,421,676	1,602,454					17
636 AA	4,790	254,733	259,523					18
336.4 ACSR	86,138	71,051	157,188					19
636 AA		20,701	20,701					20
636 AA	155,011	868,708	1,023,719					21
2500 CU PIPT								22
636 AA	17,716	1,344,121	1,361,837					23
636 ACSR	27,349	897,921	925,270					24
636 ACSR	98,570	1,391,461	1,490,031					25
636 AA								26
1259 CU PIPT		818,625	818,625					27
1272 KCM								28
636 ACSR	226,914	980,029	1,206,943					29
636 ACSR	420,061	4,679,508	5,099,570					30
336.4 ACSR								31
336.4 ACSR	212,689	1,876,460	2,089,149					32
636 ACSR								33
636 ACSR								34
336 ACSR	137,673	257,199	394,872					35
	35,991,548	219,547,198	255,538,743	11,475	3,363,663		3,375,138	36

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TRANSMISSION LINE STATISTICS (Continued)

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	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
336.4 ACSR								1
636 ACSR	117,304	627,543	744,847					2
556.5 ACSR 18.1								3
636 ACSR								4
636 ACSR	80,121	322,559	402,680					5
636 ACSR	54,800	204,663	259,463					6
600 CU PIPT	9,105	1,200,257	1,209,362					7
636 ACSR								8
636 ACSR	174,868	2,167,154	2,342,022					9
636 ACSR	531,105	4,892,001	5,423,106					10
636 ACSR								11
636 ACSR								12
636 ACSR	30,427	912,264	942,691					13
954 ACSR	259,318	1,224,705	1,484,023					14
1272 ACSR	164,367	128,377	292,744					15
1272 ACSR		555,336	555,336					16
1272 ACSR	174,912	513,962	688,874					17
1272 ACSR								18
636 ACSR								19
1272 ACSR								20
1272 ACSR								21
1272 ACSR	548,224	2,823,798	3,372,022					22
1250 CU PIPT		1,179,534	1,179,534					23
983.1 ACAR	54,807	52,458	107,265					24
636 ACSR								25
636 ACSR								26
336 ACSR	35,117	1,242,507	1,277,624					27
983.1 ACSR	268,205	501,858	770,063					28
954 ACSR								29
2750 CU KCM	544,816	2,932,159	3,476,975					30
600 CU PIPT	174,545	1,186,767	1,361,312					31
636 ACSR	10,882	348,906	359,788					32
600 CU PIPT		371,400	371,400					33
636 ACSR		34,138	34,138					34
954 ACSR								35
	35,991,548	219,547,198	255,538,743	11,475	3,363,663		3,375,138	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)	
636 ACSR	31,625	483,466	515,091					1
565.5 ACSR 18/1		1,555	1,555					2
556.5 ACSR 18/1		2,421	2,421					3
	39,431		39,431					4
								5
2-954 ACRS	414,014	736,724	1,150,738					6
2-954 ACRS	495,504	914,314	1,409,818					7
	6,594,755	41,133,989	47,728,744					8
								9
				4,232	1,240,499		1,244,731	10
				4,203	1,232,069		1,236,272	11
				3,040	891,095		894,135	12
								13
								14
								15
								16
								17
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								29
								30
								31
								32
								33
								34
								35
	35,991,548	219,547,198	255,538,743	11,475	3,363,663		3,375,138	36

Schedule Page: 422 Line No.: 29 Column: a

TRANSMISSION LINE STATISTICS:

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

Ownership percentages are as follows for the respective footnotes:

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

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Columbus Southern 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	Lines Added:						
2	C796 Don Marquis Extension		6.60	ST		1	1
3							
4	Lines Altered:						
5	9038 Hayden	Roberts 345 Kv Line	5.53	ST		1	1
6							
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44	TOTAL		12.13			2	2

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

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).

3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage	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
1033.5 KCM	ACSR		138		6,727,114	2,963,771		9,690,885	2
									3
									4
954 KCM	ACSR		345		398,418	2,239,635		2,638,053	5
									6
									7
									8
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					7,125,532	5,203,406		12,328,938	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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	ADAMS (CSP)-OH	T	138.00	69.00	13.09
2		T	69.00		
3	ADDISON-OH	T	138.00	69.00	13.00
4		T	69.00	12.00	
5		T	69.00		
6		T	13.20		
7	ADENA-OH	D	69.00	13.09	
8	ASTOR-OH	D	138.00	13.80	13.80
9		D	13.80		
10	BEATTY ROAD-OH	T	345.00	138.00	13.80
11		T	138.00	69.00	13.80
12		T	138.00	69.00	13.00
13		T	138.00	13.80	
14		T	13.20		
15	BELPRE-OH	D	138.00	13.09	
16	BERKSHIRE-OH	D	138.00	35.40	13.80
17		D	34.50		
18		D	34.50		
19	BERLIN (CSP)-OH	D	69.00	13.00	
20		D	69.00	12.00	
21		D	13.20		
22	BETHEL ROAD-OH	T	138.00	69.50	13.09
23		T	138.00	13.80	13.80
24		T	138.00		
25		T	13.20		
26	BEXLEY-OH	T	138.00	40.00	13.80
27		T	138.00	39.40	13.80
28		T	138.00	13.80	13.80
29		T	46.00		
30		T	13.20		
31					
32					
33					
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35					
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40					

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

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

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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.
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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	COLUMBIA(CS)-OH	D	40.00	13.20	
2	CONESVILLE PLANT-OH	T	345.00	138.00	34.50
3		T	138.00	69.00	13.00
4		T	138.00		
5	COOLVILLE (CS)-OH	D	69.00	13.20	
6		D	69.00	13.09	
7		D	13.20		
8	COPELAND-OH	D	69.00	13.20	
9		D	13.20		
10	CORNER-OH	D	138.00	13.09	
11	CORRIDOR-OH	T	345.00	138.00	34.50
12		T	345.00	138.00	13.80
13		T	138.00	34.50	13.80
14		T	138.00		
15	CORWIN-OH	D	138.00	13.09	
16	DAVIDSON (CS)-OH	D	138.00	13.80	
17		D	13.80		
18	DAVON-OH	D	69.00	13.20	
19	DELANO-OH	D	138.00	69.00	13.20
20	DELAWARE (CSP)-OH	T	138.00	69.00	13.09
21		T	138.00	40.00	13.80
22		T	138.00	35.40	13.80
23		T	138.00	34.50	13.80
24		T	138.00	13.80	
25		T	138.00		
26		T	34.50		
27		T	13.20		
28	DUBLIN(CS)-OH	D	138.00	13.80	
29		D	69.00		
30		D	13.80		
31	DUCK CREEK-OH	D	138.00	13.09	
32		D	23.00	13.09	
33	EAST BROAD STREET-OH	T	138.00	40.00	13.80
34		T	138.00		
35		T	40.00		
36		T	13.80	39.40	13.80
37		T	13.20		
38	ELK-OH	D	69.00	13.20	
39	ELLIOT-OH	T	138.00	69.00	13.20
40					

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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	ETNA ROAD-OH	D	40.00	13.80	4.30
2		D	13.20		
3	FIFTH AVENUE-OH	D	138.00	39.40	13.80
4		D	13.20		
5	GAHANNA-OH	D	138.00	35.40	13.80
6		D	138.00	34.50	13.80
7		D	138.00	13.80	
8		D	13.20		
9	GALLOWAY ROAD-OH	D	69.00	13.80	
10		D	13.20		
11	GAY STREET-OH	D	138.00	13.80	13.80
12		D	13.80		
13	GENOA-OH	T	138.00	70.50	13.80
14		T	138.00	69.00	12.00
15		T	138.00	34.50	13.80
16		T	138.00		
17		T	69.00		
18		T	40.00	14.50	
19	GROVES ROAD-OH	T	138.00	40.00	13.80
20		T	138.00	13.80	
21		T	138.00	13.80	13.80
22		T	138.00		
23		T	46.00		
24		T	40.00	13.80	
25		T	13.80		
26	HALL-OH	D	138.00	13.80	
27		D	13.80		
28	HANERS-OH	D	69.00	13.09	
29		D	13.20		
30	HARMAR-OH	D	23.00	4.36	
31	HARMAR HILL-OH	D	138.00	13.09	
32	HARRISON-OH	T	138.00	69.00	13.80
33	HESS STREET-OH	D	138.00	13.80	
34		D	138.00		
35		D	13.80		
36	HIGHLAND (CS)-OH	D	69.00	13.20	
37		D	69.00		
38		D	13.20		
39					
40					

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			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	HILLIARD-OH	D	69.00	13.80	
2		D	69.00		
3		D	13.20		
4	HUNTLEY-OH	T	138.00	69.00	13.80
5		T	138.00	13.80	
6		T	138.00		
7		T	69.00	13.80	
8		T	13.20		
9	HYATT-OH	T	345.00	138.00	13.80
10		T	345.00	138.00	13.00
11		T	138.00	35.40	13.80
12	IDAHO-OH	D	69.00	12.00	
13	JEFFERSON (CS)-OH	D	69.00	13.20	
14		D	13.20		
15	JUG STREET-OH	T	345.00	137.50	13.80
16		T	138.00	35.40	13.80
17	KARL ROAD-OH	D	138.00	13.80	13.80
18		D	13.80		
19		D	13.20		
20	KENNY-OH	D	138.00	13.80	13.80
21		D	13.20		
22	KIMBERLY-OH	D	138.00	13.09	
23	KIRK-OH	T	345.00	138.00	13.00
24		T	138.00	69.00	34.00
25		T	138.00	34.50	13.00
26		T	34.50		
27	LAYMAN-OH	D	138.00	13.09	
28	LAZELLE-OH	D	69.00	13.80	
29		D	13.20		
30	LEE-OH	D	69.00	12.00	
31		D	13.20		
32	LICK-OH	T	138.00	69.00	13.20
33		T	138.00		
34		T	69.00	13.00	
35		T	69.00		
36		T	34.50	12.00	
37		T	13.20		
38	LINCOLN STREET-OH	D	69.00	13.80	
39					
40					

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			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	LINWORTH-OH	D	138.00	40.00	13.80
2		D	138.00	13.80	
3		D	13.20		
4	LIVINGSTON AVENUE-OH	D	40.00	13.00	
5	MADISON (CS)-OH	D	69.00	13.80	
6		D	69.00		
7	MALISZEWSKI 138 KV-OH	T	138.00	35.40	13.80
8		T	138.00	34.50	13.80
9		T	34.50		
10	MALISZEWSKI 765 KV-OH	T	765.00	138.00	13.80
11	MARION ROAD-OH	T	138.00	40.00	13.00
12		T	138.00	39.40	13.80
13		T	138.00		
14		T	40.00	13.00	
15		T	13.80	13.80	
16		T	13.20		
17	MCCOMB (CS)-OH	T	138.00	39.40	13.80
18		T	138.00		
19		T	13.20		
20	MEIGS (CS)-OH	D	69.00	13.09	
21		D	69.00	13.00	
22		D	69.00		
23		D	13.20		
24	MIFFLIN-OH	D	138.00	13.80	
25		D	13.20		
26	MILL CREEK (CSP)-OH	D	138.00	24.80	
27		D	138.00	13.09	
28	MORSE ROAD-OH	D	138.00	13.80	13.80
29		D	138.00		
30		D	13.20		
31	MOUND STREET-OH	D	138.00	13.80	13.80
32		D	13.80		
33	OSU-OH	D	138.00	13.80	
34		D	13.80		
35	PARK-OH	D	69.00	13.80	
36		D	13.20		
37	PARSONS-OH	D	40.00	13.80	
38		D	13.80		
39	PEACH MOUNT-OH	D	34.50	12.00	
40		D	13.20	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	PICWAY-OH	T	69.00	40.00	2.30
2	POLARIS-OH	D	138.00	35.40	13.80
3		D	34.50		
4	PORTERFIELD-OH	D	138.00	13.09	
5	POSTON-OH	T	138.00	69.00	13.40
6		T	138.00		
7		T	69.00	13.20	
8		T	69.00	13.09	
9		T	69.00	12.00	
10	RARDEN-OH	D	69.00	34.50	13.00
11	RAVEN-OH	D	69.00	13.20	
12	RENO-OH	D	138.00	13.09	
13	REYNOLDSBURG-OH	D	40.00	13.20	4.15
14		D	7.50		
15	RIO-OH	D	138.00	13.20	
16		D	13.20		
17	RIVERVIEW (CSP)-OH	D	138.00	13.80	
18		D	138.00		
19	ROBERTS-OH	T	345.00	138.00	34.50
20		T	345.00	137.50	13.80
21		T	138.00	13.80	
22		T	13.20		
23		T	13.20		
24	ROSS-OH	T	138.00	69.00	13.20
25		T	138.00	34.50	12.00
26		T	138.00		
27		T	69.00	13.00	
28		T	69.00		
29		T	13.20		
30	ROZELLE-OH	D	138.00	13.09	
31	SAINT CLAIR AVENUE (CS)-OH	D	138.00	40.00	13.00
32		D	138.00	13.80	13.80
33		D	138.00		
34	SARDINIA-OH	D	69.00	13.20	
35		D	13.20		
36	SAWMILL-OH	T	138.00	69.00	13.00
37		T	138.00	34.50	13.80
38		T	138.00	13.80	
39		T	138.00		
40	SCIOTO TRAIL (CS)-OH	D	138.00	13.20	7.24

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			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	SCIPPO-OH	D	138.00	13.09	
2	SEAMAN-OH	T	138.00	69.00	13.09
3		T	69.00	13.20	
4		T	69.00	12.00	
5		T	69.00		
6	SHANNON-OH	D	138.00	13.80	
7		D	13.80		
8	SLATE MILLS-OH	D	69.00	13.20	
9	STROUDS RUN-OH	T	138.00	69.00	13.20
10		T	138.00	69.00	12.00
11	SUNBURY-OH	D	34.50	13.20	4.15
12	TAYLOR-OH	D	138.00	34.50	13.80
13	TRABUE-OH	D	138.00	69.50	13.80
14		D	138.00	13.80	
15		D	13.80		
16	TRENT-OH	D	138.00	34.50	13.80
17	VIGO-OH	D	69.00	13.20	
18		D	69.00	13.09	
19	VINE-OH	D	138.00	13.80	
20		D	138.00	13.80	13.80
21		D	138.00		
22		D	13.20		
23	WAVERLY-OH	T	138.00	69.00	13.53
24		T	138.00	69.00	13.20
25		T	138.00		
26		T	13.20		
27	WEST-OH	D	46.00		
28		D	40.00	13.80	
29		D	40.00	13.20	
30	WESTERVILLE-OH	D	69.00	13.80	
31	WHITE ROAD-OH	D	138.00	13.80	
32	WILKESVILLE-OH	D	138.00	13.09	
33	WILSON ROAD-OH	T	138.00	39.40	13.80
34		T	138.00	13.80	13.80
35		T	138.00		
36		T	46.00		
37		T	13.20		
38	WOLF CREEK (CSP)-OH	T	138.00	133.20	7.20
39		T	138.00	23.60	
40		T	138.00	13.09	

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

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SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
56	1					1
			STATCAP	1	14	2
56	1					3
20	1					4
			STATCAP	1	14	5
			STATCAP	1	4	6
20	1					7
168	2					8
			STATCAP	4	14	9
1010	2	2				10
100	2					11
56	1					12
50	1					13
			STATCAP	2	7	14
40	2					15
50	1					16
	3					17
			STATCAP	1	7	18
9	1					19
11	1					20
			STATCAP	1		21
50	1					22
167	2	1				23
			STATCAP	1	72	24
			STATCAP	6	24	25
83	2					26
42		1				27
84	1					28
			STATCAP	1	11	29
			STATCAP	4	13	30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Columbus Southern 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)	
15	1					1
675	1					2
11	1					3
			STATCAP	2		4
11	1					5
9	1					6
			STATCAP	1	2	7
11	1					8
			STATCAP	1		9
20	1					10
675	1					11
560	1					12
50	1					13
			STATCAP	1	115	14
20	1					15
92	2	1				16
			STATCAP	2	14	17
11	1					18
34	1					19
130	1					20
25	1					21
50	1					22
25	1					23
42	1					24
			STATCAP	1		25
			STATCAP	1	6	26
			STATCAP	2	14	27
150	3					28
			STATCAP	1		29
			STATCAP	2	6	30
22	1					31
1		1				32
83	2					33
			STATCAP	1	72	34
			STATCAP	1	22	35
42		1				36
			STATCAP	4	12	37
22	1					38
75	1					39
						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.
63	3					1
			STATCAP	2	10	2
42	1					3
			STATCAP	1	3	4
50	1					5
53	2					6
50	1					7
			STATCAP	2	6	8
62	3					9
			STATCAP	3	10	10
252	3					11
			STATCAP	6	38	12
90	1					13
130	1					14
92	2					15
			STATCAP	2		16
			STATCAP	2		17
20		1				18
75	1					19
50	1					20
168	2	1				21
			STATCAP	1		22
			STATCAP	1	11	23
22		2				24
			STATCAP	5	20	25
92	2					26
			STATCAP	2	14	27
25	1	1				28
			STATCAP	1	4	29
11	2					30
20	1					31
56	1					32
167	4					33
			STATCAP	1	62	34
			STATCAP	2	13	35
45	2					36
			STATCAP	1	13	37
			STATCAP	2	5	38
						39
						40

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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)	
70	3					1
			STATCAP	1	10	2
			STATCAP	2	7	3
50	1					4
83	2					5
			STATCAP	1	53	6
64	2					7
			STATCAP	4	14	8
300	1					9
300	1					10
50	1					11
11	1					12
21	2					13
			STATCAP	1	3	14
450	1					15
50	1					16
251	3					17
			STATCAP	5	25	18
			STATCAP	1	4	19
168	2					20
			STATCAP	2	10	21
40	2					22
560	1					23
90	1					24
42	1					25
			STATCAP	1	4	26
20	1					27
44	2					28
			STATCAP	1	4	29
11	1					30
			STATCAP	1	3	31
90	3					32
			STATCAP	1	43	33
2		1				34
			STATCAP	1	18	35
5		1				36
			STATCAP	2	7	37
60	2					38
						39
						40

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SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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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.
42	1					1
42	1					2
			STATCAP	2	7	3
44	2					4
20	1					5
			STATCAP	1	7	6
50		1				7
50	1					8
			STATCAP	1	7	9
750	3	1				10
83	1					11
167	2					12
			STATCAP	1	53	13
13		1				14
17	6					15
			STATCAP	5	20	16
100	2					17
			STATCAP	1	86	18
			STATCAP	2	7	19
9	1					20
11	1					21
			STATCAP	2	10	22
			STATCAP	1	6	23
97	2	1				24
			STATCAP	2	3	25
40	2					26
50	2					27
242	3					28
			STATCAP	1	72	29
			STATCAP	6	43	30
168	2					31
			STATCAP	2	7	32
50	1					33
			STATCAP	1	7	34
34	1					35
			STATCAP	1	3	36
40	2					37
			STATCAP	2	6	38
6	1					39
6	1					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.
30		1				1
100	2					2
			STATCAP	2	14	3
14	1					4
94	2					5
			STATCAP	1	50	6
11	1	1				7
11		1				8
6		1				9
38	2					10
13	1					11
20	1					12
10	1					13
			STATCAP	1	3	14
34	2					15
			STATCAP	1	3	16
45	2					17
			STATCAP	1	36	18
675	1					19
560	1					20
84	2					21
			REACTOR		40	22
			STATCAP	1	4	23
116	3					24
13		1				25
			STATCAP	1	65	26
2		1				27
			STATCAP	1	14	28
			STATCAP	3	11	29
20	1					30
42		1				31
177	2	1				32
			STATCAP	1	72	33
11	1					34
			STATCAP	1	3	35
90	1					36
149	2					37
25	1					38
			STATCAP	1	86	39
30	1					40

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			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
20	1					1
90	1					2
6		1				3
20	1					4
			STATCAP	1	29	5
92	2					6
			STATCAP	2	13	7
11	1					8
30	1					9
84	1					10
18	2					11
47	1					12
129	1					13
83	2					14
			STATCAP	2	14	15
47	1					16
11		1				17
20	1					18
92	2					19
93	1					20
			STATCAP	1		21
			STATCAP	5	29	22
30	1					23
30	1					24
			STATCAP	1	58	25
			STATCAP	2	5	26
			STATCAP	1	4	27
6		1				28
28	1					29
45	2					30
50	1					31
11	1					32
83	2	1				33
75	1					34
			STATCAP	1	72	35
			STATCAP	1	11	36
			STATCAP	2	7	37
187	1					38
20	1					39
20	1					40

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SUBSTATIONS (Continued)

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			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
50	1					1
			STATCAP	1	7	2
						3
140	26					4
						5
						6
						7
504	1					8
						9
250	1					10
1920	3					11
640	1					12
900		1				13
						14
						15
						16
						17
						18
						19
1955	2					20
910	1					21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Schedule Page: 426.8 Line No.: 6 Column: a

SUBSTATION NOTES:
- For Commonly Owned substations as noted:
- Applies to page 426.7 lines 20-39

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

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

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Summary: Annual Report FERC Form 1 for Columbus Southern Power Company electronically filed by Ms. Jatona M Cunningham on behalf of Columbus Southern Power